



Filling the Gap in New England's Decarbonization Plans: A New View of the Electric Grid

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Overview

The governors of the six New England states have announced their intention to include advanced nuclear energy in meeting this region's growing electric demand. An independent analysis of New England's current decarbonization plans shows that nuclear power will be essential to providing reliable power and will be more affordable than existing plans based upon renewable energy sources.

A newly developed modeling tool (HELGA) that simulates grid behavior hour by hour identifies deficiencies in the current plans which rely heavily on weather-dependent solar and wind generation. The analysis reveals extended periods when these resources are unable to meet the regional electricity demand.

Two major decarbonization pathways have been evaluated: *The Massachusetts 2050 Decarbonization Plan* and *The EPCET Plan* prepared by the Independent System Operator for New England (ISO-NE). Both plans greatly expand electrification and significantly increase the cost of electricity. However, despite massive expansions of solar, wind (particularly offshore wind) and battery storage at a cost of hundreds of billions of dollars, these plans still cannot reliably meet electric demand, especially in winter when failure will be most deadly. The current plans rely on "renewable natural gas" and carbon-neutral synthetic fuels to bridge these gaps, but neither yet exists at commercial scale.

This study shows that replacing much or all of these future renewable resources with always-on *baseload* nuclear power will save substantial amounts of money, keep electric rates stable, and avoid the environmental impacts of large solar and wind buildouts. Adding *flexible* nuclear systems with thermal storage can supply the essential *dispatchable* power needed to meet fluctuating demand. If these flexible facilities can, when not generating power for the region's grid, export energy to other regions, desalinate water, or produce hydrogen and synthetic fuels, they will generate electricity at costs that will be comparable with the cost of electricity today.

Nuclear power is the only currently available technology capable of providing clean, reliable, and affordable electricity at the scale required to meet the region's needs by mid-century. New England can be more confident of achieving its 2050 goals and with far less environmental disruption by incorporating baseload and flexible nuclear power into its strategy.

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1. Background

As this report was nearing completion, the governors of the six New England states issued a joint statement announcing their intention to include advanced nuclear energy as “a pillar of New England’s electric system.”¹ They recognize that electrical demand is growing and new, reliable sources that do not emit greenhouse gases will be essential to meet that need.

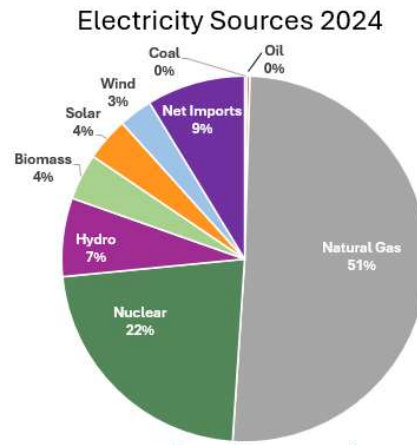
Five states in New England (excluding New Hampshire) have created public policies that emphasize the use of renewable energy sources, principally solar and wind, to replace the burning of fossil fuel. Their approach involves electrifying all of their current uses of fossil fuels and converting the region’s electric grid to one which is free of carbon emissions. Over the past decade, the region’s planners have found that, because of the intermittency of solar and wind resources and the limitations of batteries, such a plan has to utilize some form of zero-carbon fuel, either “renewable natural gas” or a synthetic hydrocarbon, to avoid repeated blackouts.

Regional planners have, until now, not been able to incorporate nuclear power into their plans beyond what already exists because of legislative restrictions in five of the region’s states. This study examines what can be done if, as the governors now agree, those restrictions are removed.

Two basic facts are exposed here: (1) Introducing nuclear power as a baseload, always-on resource, to replace much of the intermittent solar and wind that are the basis of the current plan, saves a great deal of money, and (2) every electric grid requires a firm, reliable, dispatchable source of power, capable of responding to the moment-to-moment variations in demand imposed upon it. No existing plan offers a currently available solution that can meet that need. This is a significant gap in all of the plans. Any serious consideration of this fact will lead us to recognize that the dream of a future powered by sun and wind alone is simply unattainable. A clean, reliable source that can generate power at any time is needed, one that is not dependent upon variable weather and time of day. Without it, our homes, businesses, data centers – everything – will repeatedly face power failures. That calamity will not happen under the plans suggested here, which incorporate significant amounts of clean, reliable nuclear power at a cost per megawatt-hour comparable to what New Englanders are now spending.

¹ https://portal.ct.gov/governor/news/press-releases/2026/03-2026/new-england-governors-announce-commitment-to-explore-advanced-nuclear-energy?language=en_US

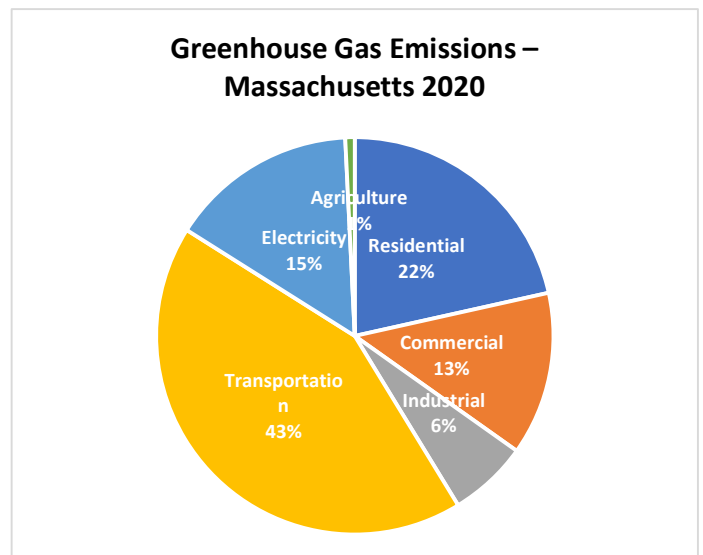
Today, natural gas and nuclear power are the main sources of electricity in New England². Only a small portion of generation is renewable (solar, wind, biomass). For those who wish to explore the production and use of each energy source in more detail for each state in New England, see the Sankey diagrams developed by the Lawrence Livermore National Laboratory. They reward careful examination.³



Just two nuclear plants supply 23% of New England’s electricity. They are Millstone Station in Waterford, CT, with two reactors at 884 & 1227 megawatts (MW), and Seabrook Station in Seabrook, NH, with a single 1250 MW reactor. A number of other reactors have served New England since the 1960s, but they were closed for a variety of economic and political reasons. These include Yankee Rowe, Connecticut Yankee, Maine Yankee, Vermont Yankee, and Pilgrim, along with Shoreham and Indian Point in New York.



It is important to recognize that electricity accounts for only a small portion of New England’s greenhouse gas emissions. This figure shows an estimate of the GHG emissions for Massachusetts in 2020⁴.



Decarbonization will require eliminating, as far as possible, the emissions from all the other sectors of the economy. The current approach to achieve this is to decarbonize the electric grid by replacing the burning of coal (largely accomplished), oil (still burned in mid-winter periods), and natural gas

² <https://www.iso-ne.com/isoexpress>

³ <https://flowcharts.llnl.gov>

⁴ Ibid.

with “clean”, zero-emission sources including solar, wind, and nuclear power. As the preceding chart suggests, the sources of emission are widespread. Eliminating them will not be an easy task.

Legislation in each state in New England except New Hampshire aims to reduce overall GHG emissions by at least 80% by 2050, replacing the burning of fossil fuels in all sectors of the economy through electrification. Electricity, which currently accounts for just 15% of New England’s emissions, would have to be greatly expanded to power every sector of New England’s economy, and it would have to be supplied by clean, carbon-free sources.

Currently, all but New Hampshire restrict adding any new generation of nuclear power. Connecticut, Massachusetts, and Maine require that there be a solution for waste disposal before new nuclear plants can be built. Massachusetts, Rhode Island, and Vermont require that their state legislatures approve of any new nuclear installations, and Maine and Massachusetts require that voters approve any new nuclear plants.

Two decarbonization plans have been developed by New England planners. In 2020, the Massachusetts Executive Office of Energy and Environmental Affairs published the *Massachusetts 2050 Decarbonization Roadmap*⁵. This study, which presented a varied series of “pathways” towards net-zero greenhouse gas emission by 2050, provided the basis for a regional *Clean Energy and Climate Plan* (CECP) for 2025, 2030, and 2050 which was published in 2023⁶. In 2024, the Independent System Operator for New England (ISO-NE), which operates New England’s unified grid, published its report entitled *Economic Planning for the Clean Energy Transition* (EPCET)⁷. Both planning exercises assume a broad expansion of renewable sources: rooftop and utility-based solar, land-based wind and especially offshore wind. Because of state restrictions on the use of nuclear power, along with widespread popular support for solar and wind power, neither study assumes any expansion of nuclear energy.

⁵ <https://www.mass.gov/info-details/ma-decarbonization-roadmap>

⁶ <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030>

⁷ https://www.iso-ne.com/static-assets/documents/100014/epcet_policy_final_results.pdf

2. A New Model of the Electric Grid

This study applies a new computer-based model to describe the behavior of the electric grid on an hour-by-hour basis. This new model is called HELGA, the Hourly ELectric Grid Analysis Model. It was originally developed by Reiner Kuhr, a power engineer with broad experience, and a software developer, Ahmad Nofal and applied to New England planning through 2030.⁸

This program provides an hourly dispatch model of a proposed scenario for any selected year. For each hour in the year, it sequentially introduces all of the electric generators: first, the fixed non-dispatchable ones – existing nuclear power, hydropower, other renewables, imports, wind, and solar – and then, the flexible dispatchable sources – batteries, natural gas, and nuclear. The Kuhr-Nofal model has previously been adapted to analyze decarbonization scenarios developed for New York⁹ and California¹⁰.

The flow of calculations in the HELGA Model (For details, see Appendix C.)

The HELGA model operates as follows:

Step One: Assumptions and data include projected loads and energy source capacities for each year. We focused on the target year of 2050. The hourly load and energy source outputs, including solar and wind outputs per unit of capacity, for weather year 2024 were used for 2050.

Step Two: Calculations are performed for each of the 8760 hours in the year. First, the contributions of the fixed, non-dispatchable sources – Existing Nuclear, Hydro, Other Renewables (biomass), Imports (treated as fixed), Wind, Solar, New Nuclear – are introduced. Then, the controllable, dispatchable sources – Battery Discharge, Gas, Oil, Flexible Nuclear – are introduced, one by one, ordered by their marginal cost, the least expensive first, until they meet the total demand or gross load on the grid. Finally, if there is any excess power available from the fixed sources, it is used for Battery Charge. If there is still excess power available, it is “curtailed”, that is, shut down to avoid overloading the grid.

⁸ https://www.nuclearmy.org/wp-content/uploads/2025/05/RKuhr_ANofal-Technical_&EconomicLimitsforRenewable-2022.pdf

⁹ https://www.nuclearmy.org/wp-content/uploads/2024/06/Filling_the_Gap_in_New_Yorks_Decarbonization_Plan-LRodberg.pdf

¹⁰ <https://anthropoceneinstitute.com/wp-content/uploads/2024/09/A-New-View-of-Californias-Decarbonization-Plan-LRodberg.pdf>

Step Three: The hourly data for a year is combined to produce the annuals for each source including generation, curtailment, and cost. Capacity factors – the fraction of potential output that a source is actually producing – are calculated (these are not, as in some models, assumed from the beginning).

Step Four: Visualizations are created including hourly graphs by day, week, and year for load, generation, and curtailment by source.

Inputs and Assumptions in the New England Model

1. The ISO-NE service area is treated as a single zone.
2. Source capacities, hourly generation by source, and system load for 2024 are from ISO-NE.
3. Source capacities and projected load for 2050 are taken from studies conducted by the Massachusetts Executive Department of Energy and Environmental Affairs and ISO-NE.
4. Hourly source outputs per unit of capacity are from ISO-NE for the year 2024. The solar and wind outputs for each hour in 2050 use the projected capacities at that time.
5. Existing Nuclear, Hydro, and Other Renewables in 2050 are treated as unchanged from 2024. Imports are based on 2024 values but are reduced if they overload the grid.
6. Batteries are charged by excess solar, wind, and new baseload nuclear output.
7. Batteries, Natural Gas, and other flexible sources (if available) provide the required output when the non-dispatchables – Existing Nuclear, Large Hydro, Other Renewables, Imports, Wind, and Solar – are not able to meet the projected load.
8. Utility Solar, Land-based Wind, Offshore Wind, and any new baseload Nuclear are curtailed if they would produce unneeded power. The sequence of curtailment for the three types of renewables is changed each day, so each type is equally exposed to curtailment over the year. Rooftop Solar is assumed to be non-curtable.
9. Current and projected costs are taken from the Moderate projection in the 2024 Annual Technology Baseline (ATB) of the National Renewable Energy Laboratory (NREL).¹¹ Natural gas is priced at \$2.50 per MMBtu (\$0.25 per therm). The ATB projects a 50% reduction in the capital cost of solar and wind by 2050, while nuclear facilities are estimated to cost \$7600 per kw if built in the near future and \$5,000 per kw built in 2050. (Note: The average cost of nuclear

¹¹ <https://atb.nrel.gov/electricity/2024b/data>

plants built in the 1960-1990 period was \$8,200 per kw.¹²) The price of fossil natural gas is assumed to be \$3 per MMBtu or \$17/MWh.

10. A capital recovery factor of seven percent of capital cost per year is used for all sources.

11. In determining the size of new and flexible nuclear facilities in the alternative scenarios, we chose the minimum size required to meet the demand. In real world applications, extra facilities would be added to assure reliability in the event that one or more reactors should experience a breakdown or unplanned outage.

New England's Daily Generation of Electricity for 2024

Figure 2.1 that follows shows how the operation of New England's grid looks for 2024 on a daily basis. Reading from the bottom-up are, first, sources that are treated here as fixed – existing nuclear plants, hydropower, the “other renewables,” mainly wood and municipal waste – and imports from Canada and New York State. (To simplify the operation of the model in what follows, these are assumed to be unchanged from the values they had in 2024.) Then, moving up, are the variable “non-dispatchable” sources whose output is dependent upon the weather. Importantly, these are independent of the actual demand on the grid and not responsive to it. Finally, at the top of the graph, in gray, is dispatchable natural gas, filling in whatever gap remains between what is supplied by the non-dispatchables and the actual demand on the grid.

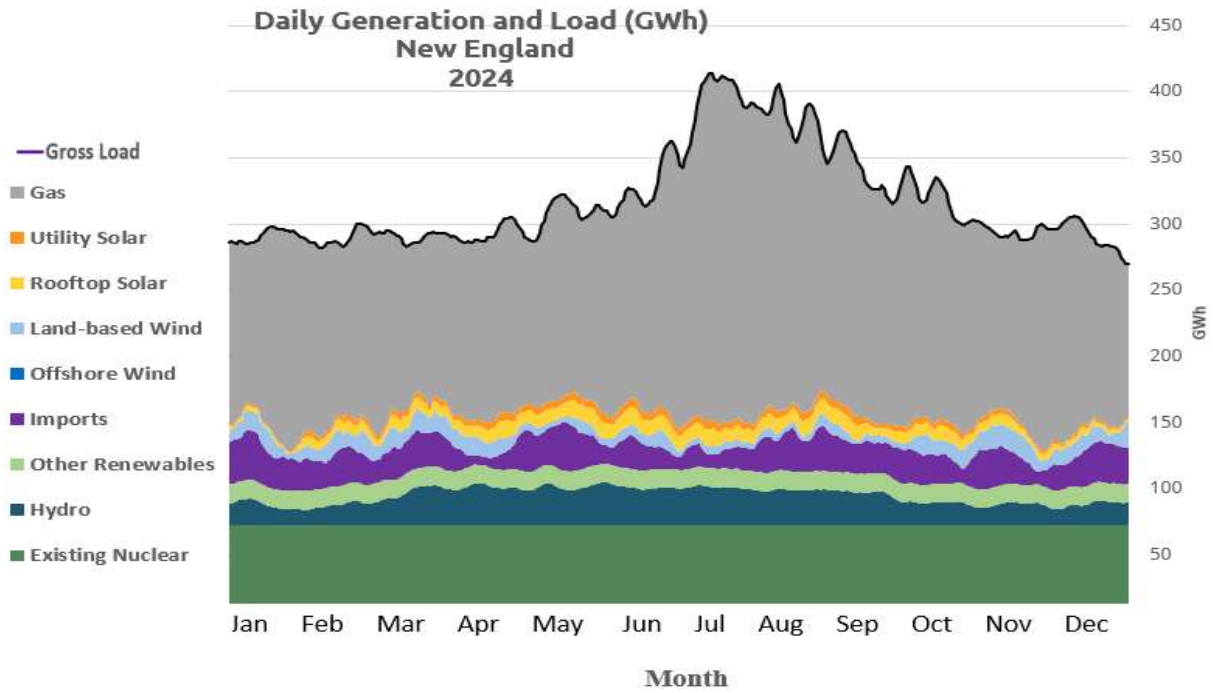
The majority of power is currently supplied by the burning of natural gas and by a small amount of oil during the summer peak (and sometimes during winter cold snaps). The two nuclear plants run steadily throughout the year, except for a few weeks every eighteen months when they shut down for refueling. Wind power fluctuates throughout the year. Solar is strongest during the summer, with far less output during the winter, that is, at the start and end of the year. Together, these renewable sources supplied less than 10% of the energy needed by the grid.

The average wholesale cost – the cost of electric generation shown in the accompanying table, does not count the cost of transmitting, distributing, and managing the delivery of electricity to the end users, and –ignoring any subsidies – is estimated to have been \$63.20 per megawatt-hour (MWh), or 6.3 cents per kilowatt-hour (kwh).¹³ (Detailed data can be found in Appendix D.)

¹² Private communication, Charles Komanoff, March 2026. Also see C. Komanoff, *Power Plan Cost Escalation*, Van Nostrand Reinhold, 1981.

¹³ Note: In New England today, generation costs are 50-60% of residential rates. The non-generation costs, consisting of transmission, distribution, and management, are \$40-50 per MWh.. <https://www.eia.gov/electricity/data.php#revenue>. Transmission costs are expected to rise substantially as more

Figure 2.1 – New England 2024



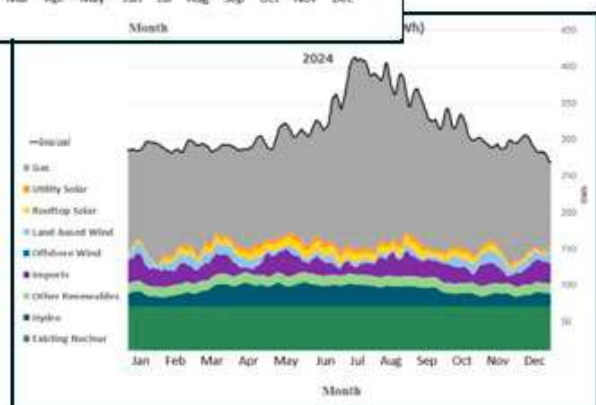
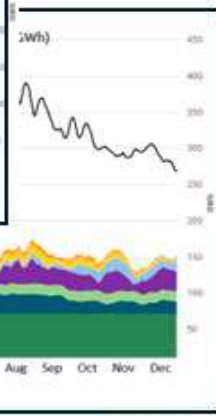
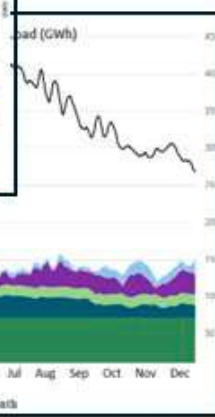
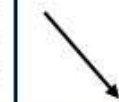
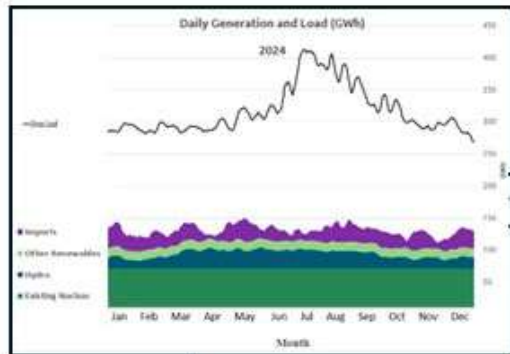
If you have difficulty with the above graph, see the next page for a guide to reading it.

| Electricity Generation | | | | |
|----------------------------|------------------------|-----------------|---------------------|---------------|
| 2024 | | | | |
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 22.8% |
| Hydro | 2,766 | 8,173 | 33.7% | 7.0% |
| Other Renewables | 763 | 5,210 | 78.0% | 4.5% |
| Rooftop Solar | 2,493 | 3,037 | 13.9% | 2.6% |
| Utility Solar | 1,247 | 1,519 | 13.9% | 1.3% |
| Land-based Wind | 1,253 | 3,521 | 32.1% | 3.0% |
| Offshore Wind | 0 | 0 | 0.0% | 0.0% |
| Battery Discharge* | 160 | 0 | 0.0% | 0.0% |
| Gas | 30,000 | 60,019 | 22.8% | 51.7% |
| Imports | | 8,221 | | 7.1% |
| Load | | 116,179 | | 100.0% |
| Curtailment | | 0 | | 0.0% |
| Total Cost (\$/MWh) | Current \$63.20 | | | |

*Battery charging load is part of solar and wind output.

widely distributed solar and wind installations are built. See https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

Insert 1: How to Read the Daily Generation Graphs



To read a Daily Generation graph, start from the bottom of the graph, where you'll find the sources that are treated as unchanged from their values in 2024: existing nuclear, hydro, other renewables (wood, municipal waste, etc.), and imports. Moving up on the graph, you'll find wind, both offshore and land-based. Then moving up further, you'll find solar, both rooftop and utility. Finally, at the top, reaching up to the gross load, you'll find gas, as much as is needed to meet the demand on the grid.

3. Two Decarbonization Plans for New England

Two plans have been put forward to decarbonize energy use in New England. Both are based on a substantial expansion of solar and wind power. The Commonwealth of Massachusetts developed a comprehensive plan with the assistance of several contractors. The Independent system Operator for New England, ISO-NE, which operates the six-state New England grid, put forward a plan as part of an economic analysis which it published in 2024. Beyond these, Mark Jacobson and colleagues at Stanford University and elsewhere have put forward a plan for New England which includes New York State. It, too, relies only on renewable energy – wind, water, and solar, or WWS. Our analysis of this plan appears in Appendix A. This plan is very expensive and, by excluding any dispatchable source, fails to provide reliable power to the region.

The Massachusetts Decarbonization Roadmap

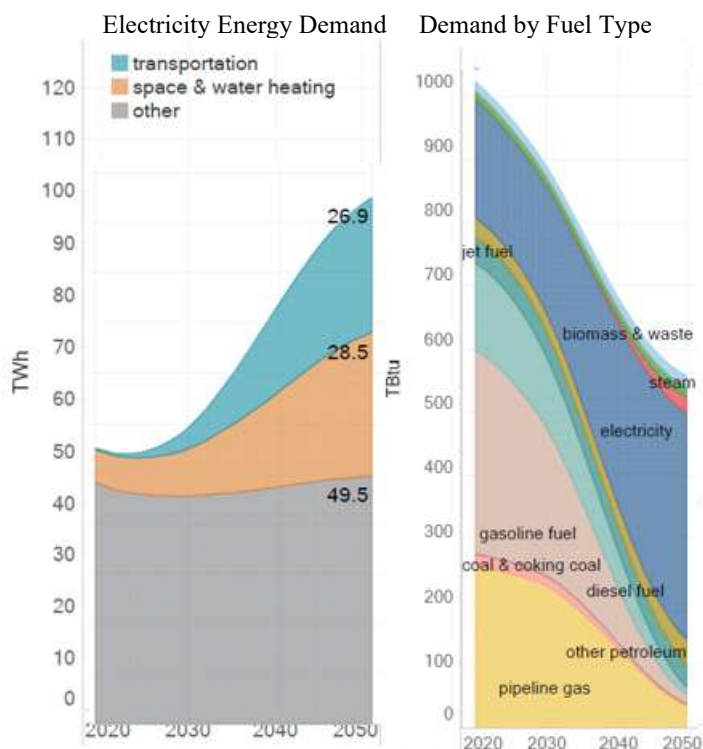
In 2020, Massachusetts issued the *Massachusetts 2050 Decarbonization Roadmap*, a comprehensive plan to decarbonize all forms of energy usage.¹⁴ It relied on electrification of every use of fossil fuels and greatly expanded use of renewable energy sources. Nuclear power was not considered to be an available option.



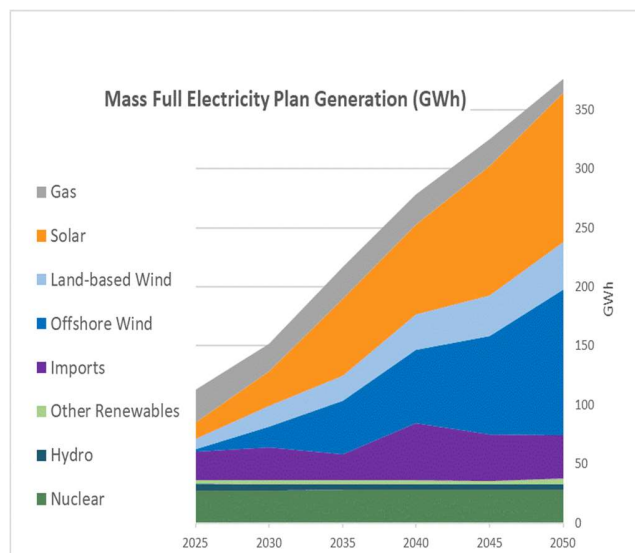
¹⁴ Massachusetts 2050 Decarbonization Roadmap. <https://www.mass.gov/info-details/ma-decarbonization-roadmap>

The *Massachusetts Roadmap* shows that the demand for electricity will double as space and water heating is converted to all-electric and electric vehicles replace gasoline-driven vehicles.

The detailed companion report to the Roadmap, *Energy Pathways to Deep Decarbonization*, shows these features.¹⁵ The first graph here shows the doubling of demand on the electric grid from these new uses of electricity, while the second shows the expansion of electricity (dark blue) even as other fossil-based energy sources, though reduced, remain significant.



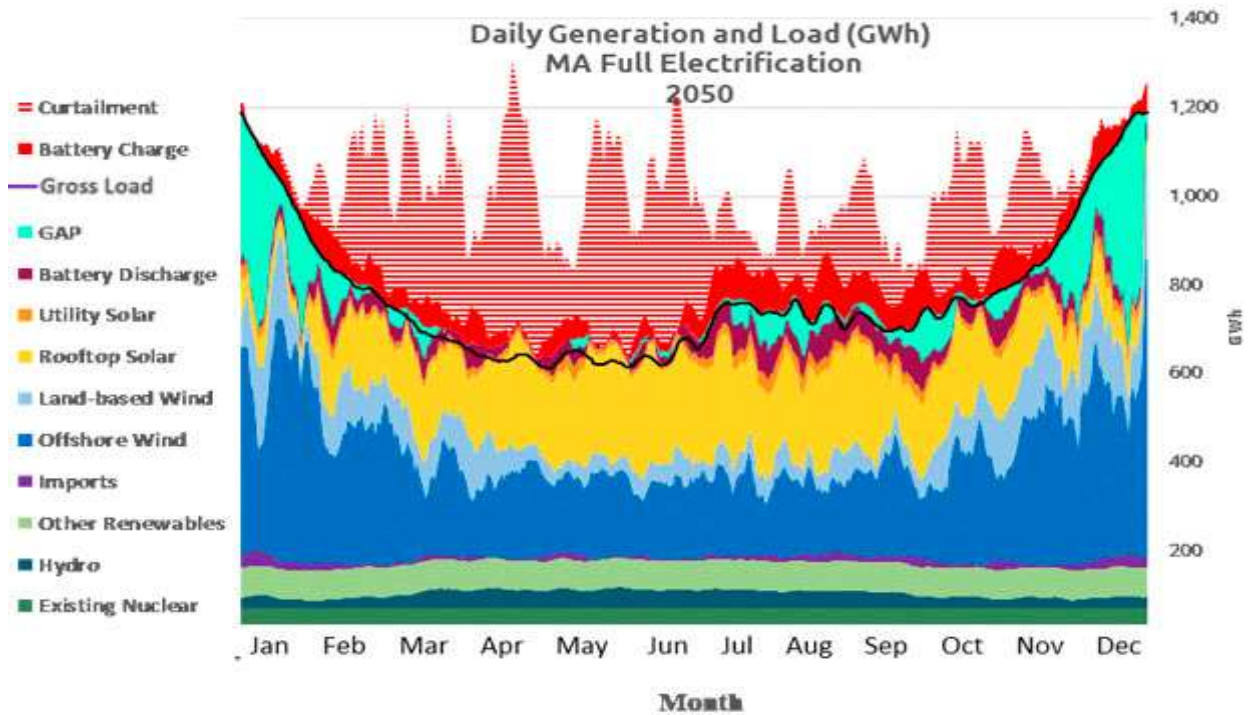
The capacity of the electric grid expands, but gas-burning continues, too. In this study, we analyze the Massachusetts plan for Full Electrification, the most ambitious of the plans in the *Massachusetts Workbook of Energy Modeling*.¹⁶ The result is shown in Figure 3.1 on the next page and explained in further detail below.



¹⁵ <https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download>

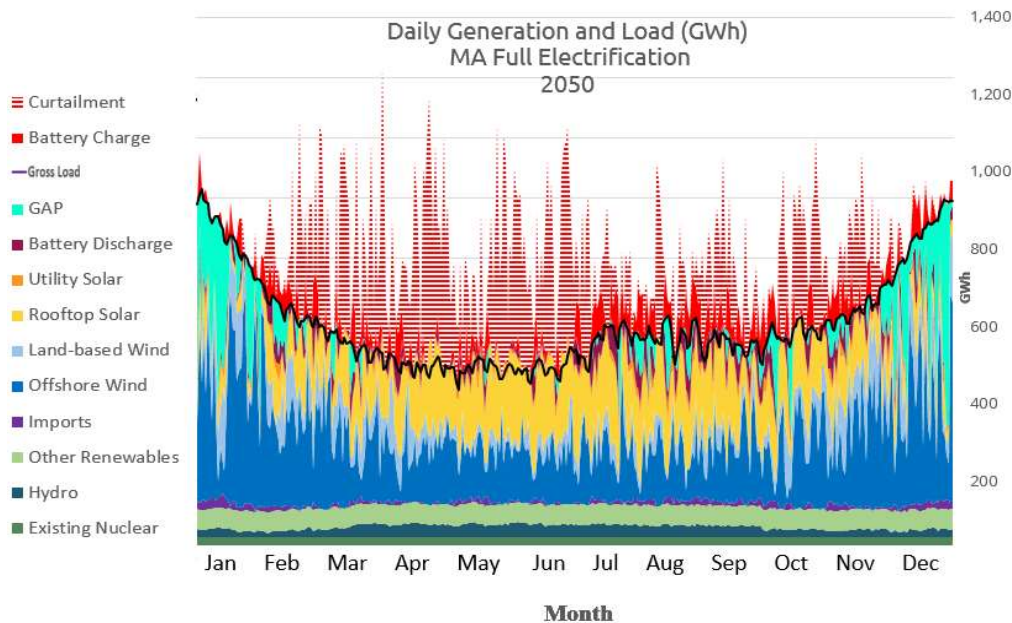
¹⁶ <https://www.mass.gov/doc/massachusetts-workbook-of-energy-modeling-results/download>

Figure 3.1 – MA Full Electrification 2050

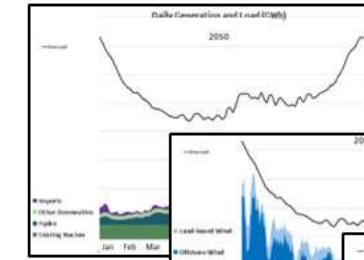


If you have difficulty with the above graph, see the next page for a guide to reading it.

Figure 3.1, and all similar figures in what follows, use a 7-day rolling average to smooth out the rapid daily variations in renewable output, especially of the offshore wind. Below is what the actual daily data looks like. A display of hourly data would show even more rapid variations, revealing the increased complexity associated with wind and solar.



Insert 2: How to Read the 2050 Daily Generation Graphs



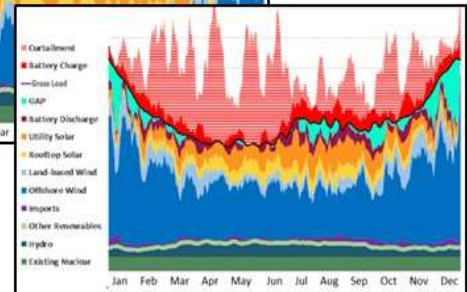
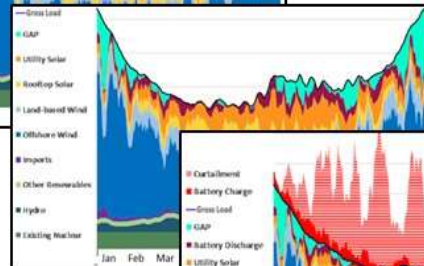
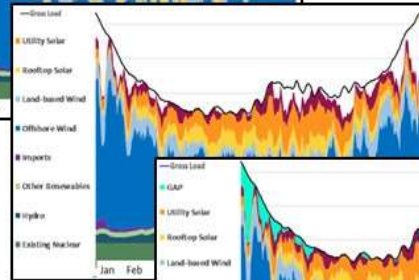
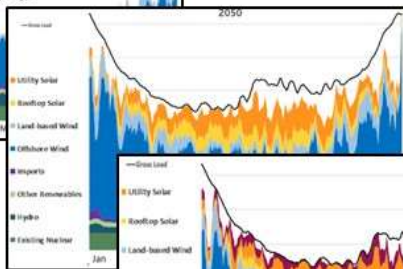
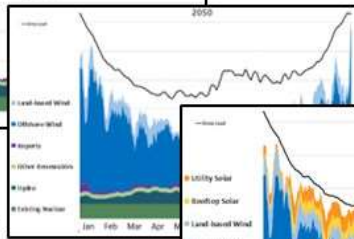
To read a 2050 Daily Generation Graph, start from the bottom, with the sources that are unchanged from their values in 2024.

Move up to find the wind power, offshore and land-based. Moving up, you'll find the solar power, first rooftop, then utility-based.

Still moving up, you will find, in deep purple, the contribution of discharge of the batteries.

Then, just below the line representing the gross load – the demand on the grid – you'll find the Gap, the difference between the demand on the grid load and the supply from all the other available sources. This Gap will have to be filled by various types of emission-free or carbon-neutral energy sources.

Finally, above the line for the gross load, you'll find the charging of batteries in dark red. Above that, in dashed red lines, is curtailment, the excess wind and utility solar output (and possibly new baseload nuclear output) which can be produced but is not needed.



Notably, the graphs show that there will be times when solar and wind, including the large installations envisioned for offshore wind, will be inadequate to meet this growing demand (note the Gap, in aqua). Further, some energy uses, including long-range aircraft and long-distance trucking, are difficult or impossible to electrify. To fill in this gap between what the renewables can supply and the demand on the grid, the MA Roadmap includes a large amount of non-renewable energy or fuels created using renewable energy from an unspecified source.

Renewables need assistance from natural gas for much of the year

Figure 3.1 shows that electric demand in 2050 is greatest at the beginning and end of the year, winter time, because of the projected growth in electric heating. In this plan, offshore wind is the largest contributor to the grid throughout the year. Batteries are charged (depicted in red) by excess solar and wind power and discharged (shown in purple) throughout the year. The sun's contribution is largest during the middle of the year but is nearly absent during the winter, leaving a large, unfilled gap just when demand is greatest. This gap, shown in aqua in this and in subsequent figures, is largest in the winter when blackouts are most dangerous to human health.

The renewables, though often insufficient, frequently generate much more power than is needed, making them available to charge the batteries. Even so, they are often curtailed – disconnected from the grid – due to over-supply. Since the sun and wind are so variable and intermittent, there is a repeated gap between demand and supply. Natural gas or some other fuel has to be burned more than 40% of the days in a year, and nearly every day during the winter, to ensure that the lights stay on. (See the datasheet in Appendix D for further details.)

The Massachusetts Roadmap is expensive. At current prices, electric generation costs for each unit of electric energy (that is, dollars per megawatt-hour) would be three times what they are today (see Appendix D, page 50). Using projections from the National Renewable Energy Laboratory for 2050, which forecasts a steep decline in solar and wind prices, they would still be 50% greater than they are today.

Figure 3.1 shows, in dashed red lines above the Gross Load or electric demand, the Curtailments, the excess energy that Utility Solar, Land-based and Offshore Wind (and, in Sections 4 & 5, New Nuclear) could supply but is not needed by the grid. ISO-NE controls the output of these sources and will shut them down so as not to overload the grid. In our modeling, we assume that Rooftop Solar is not centrally controlled and, therefore, is not curtailed.

Something more than renewables will be needed to fill in the gap

The Massachusetts planners, with the support of their modeling contractors, found that, even with the large expansion in solar and wind power capacity, the demand on the grid could not be met without the addition of a large, dispatchable, fuel-based source. Since they were restricted to using only renewable energy sources, that fuel had to be produced using these sources only. As they declared,

“The use of low- and zero-carbon fuels, synthesized mainly from biomass and from ‘green hydrogen’ produced by zero-carbon electricity, is likely necessary to achieve Net Zero by 2050.”¹⁷

What these fuels would be, and where they would be obtained, is not specified in these studies.

ISO-New England’s EPCET Study

ISO-NE has been conducting extensive studies of the requirements on the grid created by the decarbonization plans developed by the states in New England. The most recent, and most sophisticated, of these is the study entitled *Economic Planning for the Clean Energy Transition*, or EPCET, published in 2024.^{18,19} Following the mandates of the five states, ISO-NE created scenarios focused, like that in the Massachusetts study, on renewables. Even though its projected demand was smaller than that in the Massachusetts study, it still found that a large expansion of renewable source capacities would be required. In fact, one key conclusion from EPCET is that generating capacity must be quadrupled under the current mandates:

“Renewable-only build-outs may be vast. A 2050 resource mix that includes current resources and adds a build-out of wind, solar, and battery storage ... would require approximately four times the capacity of today’s system.”²⁰

Another key conclusion of the EPCET study is that a source of zero-emission dispatchable energy – power that can be counted on to be available and can be adjusted moment to moment to meet varying demand – will be essential for a reliable, always-on grid:

“New zero-carbon dispatchable energy technologies like synthetic natural gas and small modular nuclear reactors could ensure reliability during such times.”

Our HELGA analysis confirms the ISO-NE conclusions. Figure 3.2 (page 19) shows the behavior of EPCET’s Reference Policy Scenario during the year 2050, using weather patterns from 2024. Like the Massachusetts study, it, too, shows a large gap (again shown in aqua)

¹⁷ <https://www.mass.gov/info-details/ma-decarbonization-roadmap>

¹⁸ https://www.iso-ne.com/staticassets/documents/100014/epcet_policy_final_results.pdf

¹⁹ <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf>

²⁰ <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report-fact-sheet.pdf>

between the demand on the grid and what is supplied by the various renewable sources, including the batteries. The EPCET scenario, too, needs a lot of natural gas or some unspecified renewable or carbon-neutral fuel to keep the lights on. (In order to estimate the cost of electricity under this scenario, we assume that natural gas is burned to meet this need. Any other choice is likely to cost more.)

The ISO-NE foresees lower demand than the Massachusetts planners predicted. Again, offshore wind is the largest source of power. And, at current prices, the cost is three times what is spent today to generate a megawatt-hour of energy.²¹

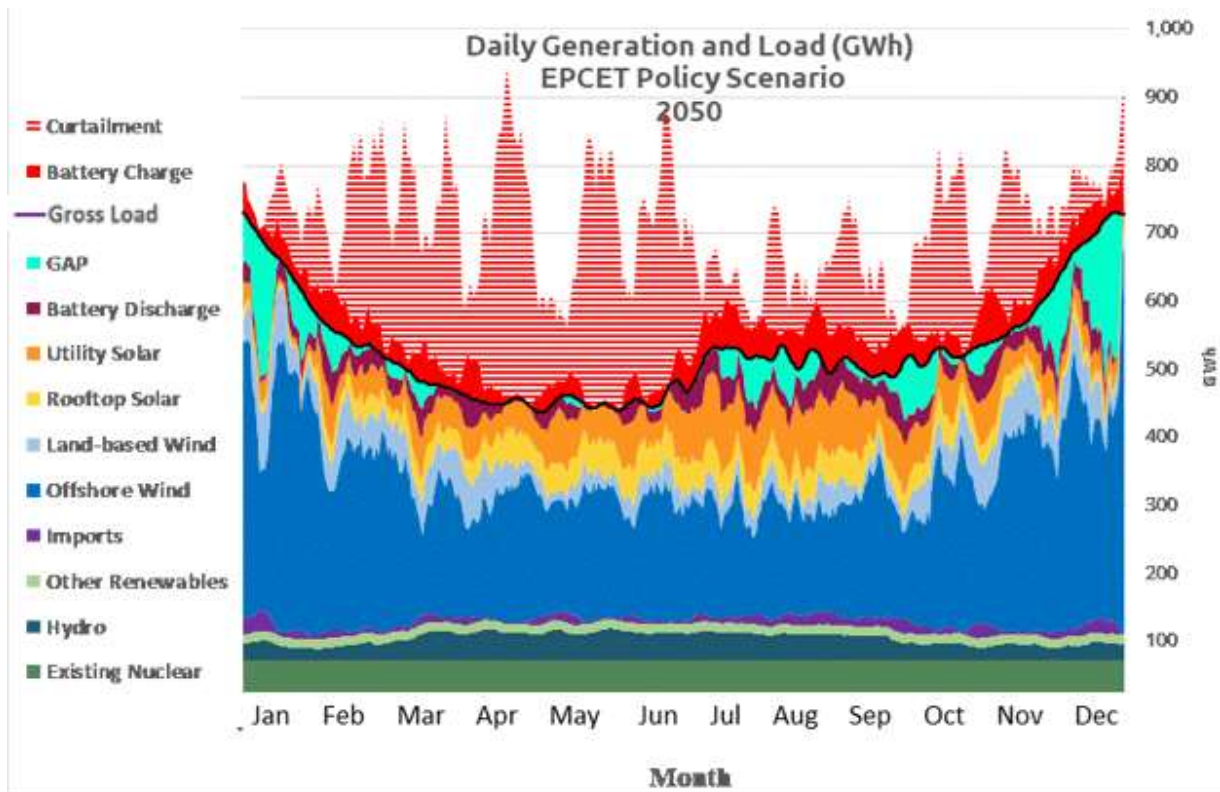
The intermittent renewables leave large gaps on many days throughout the year. As a result, though the gap accounts for less than 6% of the load, it appears at some point during one-third of the days in the year, especially during the winter.

Characteristics of the EPCET Policy Scenario

In 2050 under this scenario, most power will be fully supplied by renewable resources, mainly wind and solar. However, the grid will still rely on significant amounts of fossil resources on days with low wind and inadequate solar output. Following days of low wind and solar generation, the battery storage will be depleted, so a secure resource is needed that can fill the gaps and ensure reliability. New England's fossil gas supply plays that role today. ISO-NE's planners assume it will be replaced with some zero-emission fuel that doesn't exist today, such as carbon-neutral synthetic natural gas produced from hydrogen electrolysis and direct air capture of carbon dioxide. We use fossil natural gas here so as to be able to estimate the cost of this scenario (see Figure 3.2 Electric Generation table).

²¹ Note: In New England today, generation costs are 50-60% of residential rates. The non-generation costs consist of the cost of transmission, distribution, and management. <https://www.eia.gov/electricity/data.php#revenue>. Transmission costs are expected to rise as the load increases and distributed solar and wind resources expand. See https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

Figure 3.2 - EPCET Policy Scenario w/100% Renewable Energy 2050



| Electricity Generation EPCET Policy Scenario 2050 | | | | |
|---|-------------------------|---------------------------|---------------------|---------------|
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% |
| Utility Solar | 27,538 | 22,505 | 9.3% | 11.5% |
| Land-based Wind | 7,500 | 15,952 | 24.3% | 8.2% |
| Offshore Wind | 34,406 | 86,479 | 28.7% | 44.3% |
| Battery Discharge* | 27,500 | 9,524 | 4.0% | 4.9% |
| GAP | 25,000 | 11,352 | 5.2% | 5.8% |
| Imports | | 3,723 | | 1.9% |
| Load | | 195,352 | | 100.0% |
| Curtailment | | 53,884 | | 27.6% |
| Total Cost (\$/MWh) | Current \$184.93 | Projected \$107.61 | | |

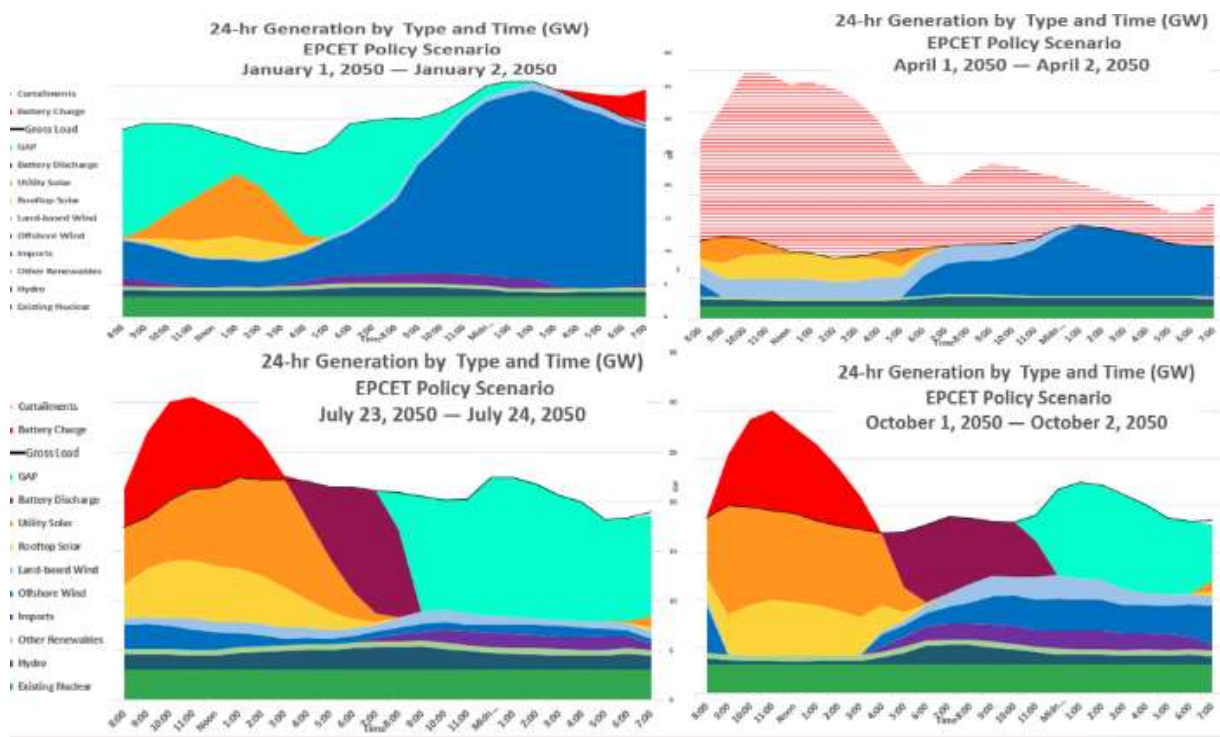
*Battery charging load is part of solar and wind output.

As in the case of the MA 2050 Roadmap, at current source prices electricity in the EPCET plan would cost, per megawatt hour, three times what electric power costs today, and in 2050, with greatly reduced solar and wind unit costs, it would cost 70% more than today's costs.

Four Days Through the Seasons in 2050 in the EPCET Policy Scenario

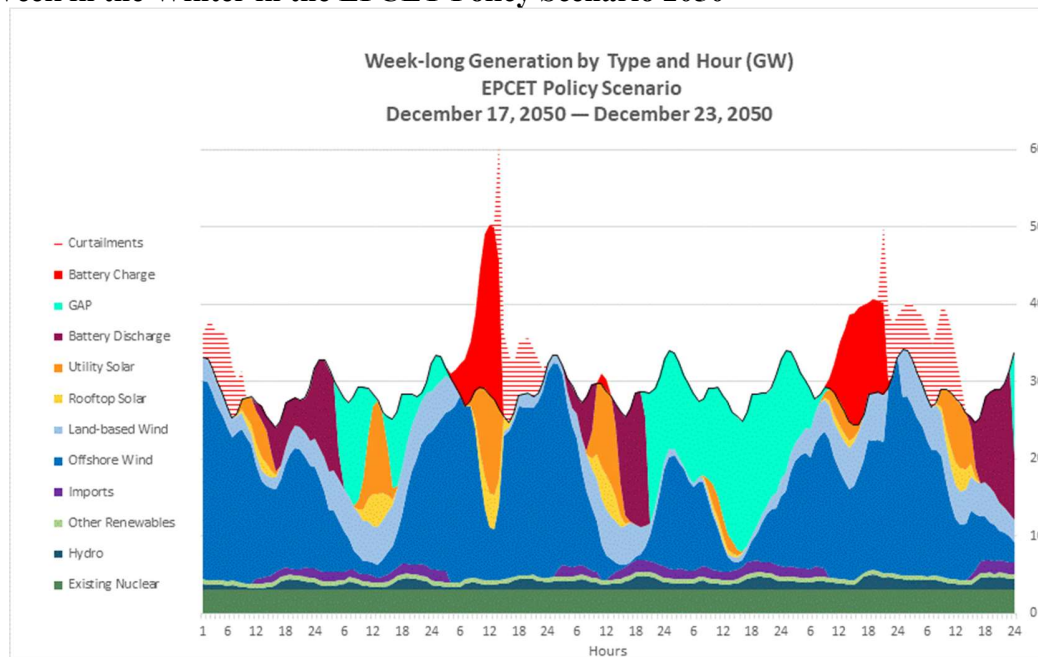
On January 1, the sun and wind are weak, and gas takes over to fill the aqua gap for much of the day. By April, demand is down, and the sun and wind are so strong they have to be curtailed (red hatched area). By July, the load has increased from the operation of air conditioners, and the wind is unreliable. The batteries are charged (solid red), but they are not sufficient (discharge, shown as purple), and gas is burned to keep the lights on in the gap through the night. Again in October, the batteries help out for awhile, but they don't last through the night.

Four Days Through the Seasons in the EPCET Policy Scenario 2050



The unreliability of wind is most apparent when looking at a full week in winter, when the sun is weak and is up for the fewest hours, and snow may be covering the panels. Then gas or some other fuel will be needed for days at a time.

A Week in the Winter in the EPCET Policy Scenario 2050

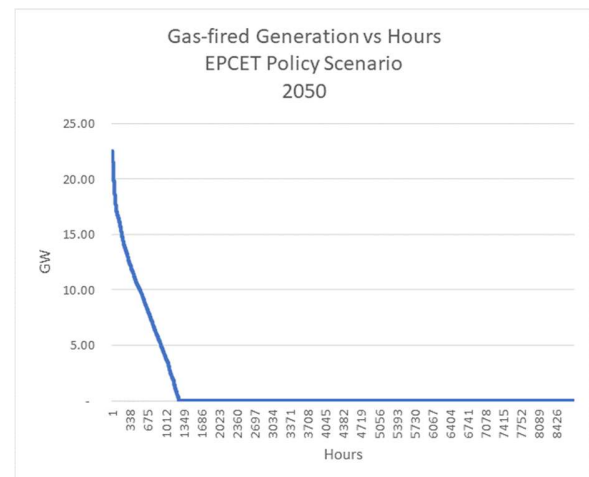


The gap-filler is needed for 1300 hours in the year

The ISO-NE planners assume the gap could be filled by using a carbon-neutral synthetic fuel to fire gas turbines, as natural gas does now.

This curve shows the number of hours that the gap-filler, here assumed to be gas-fired generation, is needed and how large is the load it must carry.

At times, it supplies most of the generation, and it has to meet some of the load during one of every seven hours during the year. For a few hours, this means carrying nearly the full load.



4. Pursuing A Reliable, Affordable, Emission-free Backbone for the Grid

This report explores several alternate plans to provide reliable, affordable carbon-free energy to power the New England grid. These plans use nuclear power with and without renewables as an always-on baseload source and as a flexible, dispatchable source. All these alternatives use the EPCET Policy Scenario as their starting point.

An alternate plan: Treat baseload nuclear as *backbone*, replacing grid-based renewables

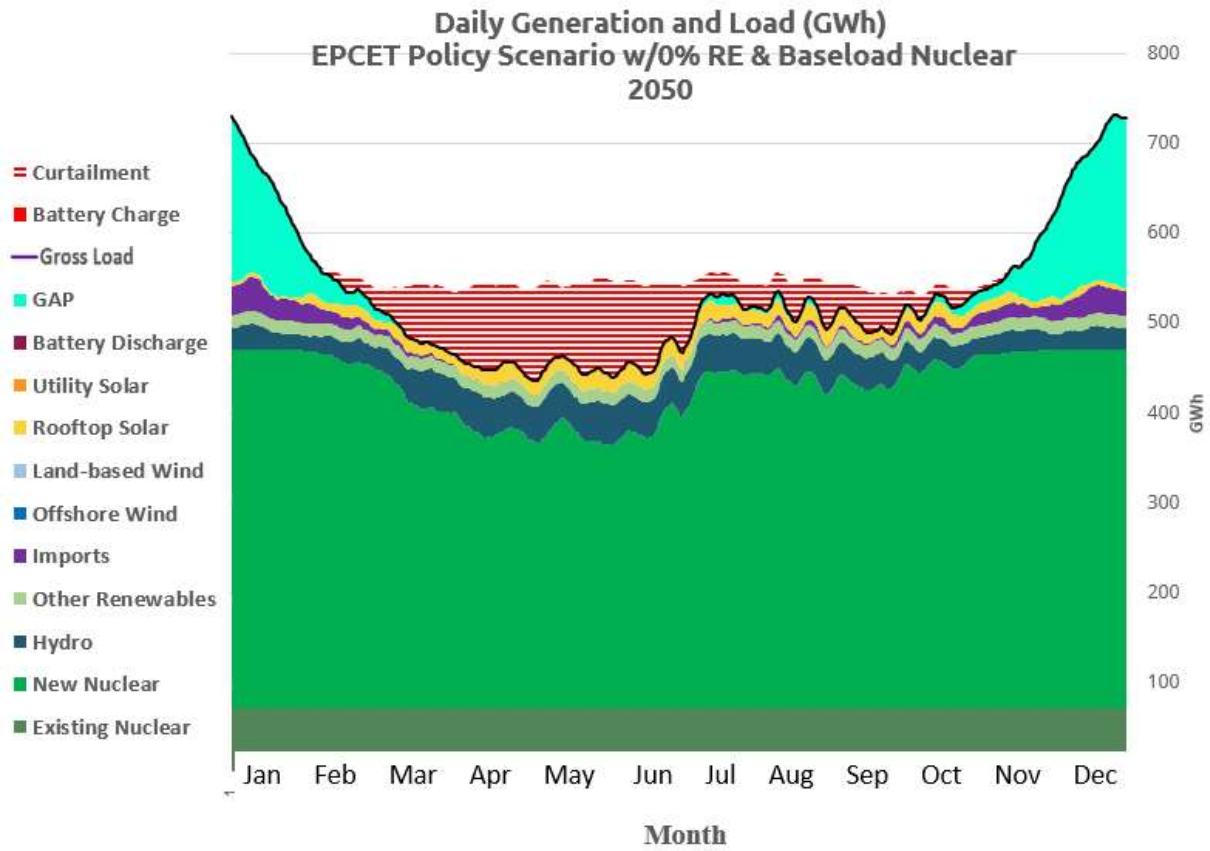
The Massachusetts and ISO-NE planners have been operating under the constraint that they not allow nuclear energy to expand in their analysis, even though it has all the attributes that would qualify it for inclusion: It emits no carbon dioxide, it requires little land and has limited impact on the environment, and the states of New England have long experience with operating nuclear plants. There is also, throughout the United States, a growing awareness of the enhanced reliability that nuclear can bring to the grid.

So, consider a scenario in which nuclear plants, operating as an always-on, baseload source of power, serve as the *backbone* of the system, replacing the wind, utility solar, and batteries in the EPCET Policy Scenario. Figure 4.1 shows the result of incorporating enough new nuclear to serve as a reliable baseload resource while among the renewables, retaining only the rooftop solar in the EPCET study.

The resulting scenario adds 18 GW of New Nuclear, the equivalent of nine Millstone plants. Replacing most of the renewables are nuclear reactors like the two 1,100 MW Westinghouse AP-1000 reactors recently completed at the Vogtle site in Georgia. However, enough of them are installed in this example to require that some of them be shut down (curtailed, shown in dashed red) some of the time. There is still a gap in the colder parts of the year requiring a flexible dispatchable source with a capacity of 25,000 MW running as often as in the original EPCET Policy Scenario. The introduction of nuclear power leads to electricity which costs much less than that in the original renewable-focused EPCET Policy Scenario.²² The cost of this plan is just 53% of the cost of the EPCET plan, at current prices, and 67% of that plan's cost, at NREL projected prices in 2050.

²² Note that the scenarios shown in Figures 3.2, 4.1, and 4.2 are not optimized for overall cost. Rather, they show the cost of electricity when the annual energy gap (in megawatt-hours) remains around 5% of total annual demand. Natural gas is assumed to fill that gap in this scenario. Once a clean energy source that can serve as gap filler is identified, an improved, lowest-cost scenario can be identified (see Figure 5.4).

Figure 4.1 - EPCET Policy Scenario w/0% Renewable Energy & Baseload Nuclear 2050



| Electricity Generation | | | | |
|--|----------------------|------------------------|----------------------------|----------------|
| EPCET Policy Scenario w/0% RE & Baseload Nuclear 2050 | | | | |
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% |
| New Nuclear | 18,000 | 131,341 | 83.3% | 67.9% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% |
| Utility Solar | 0 | 0 | 0.0% | 0.0% |
| Land-based Wind | 0 | 0 | 0.0% | 0.0% |
| Offshore Wind | 0 | 0 | 0.0% | 0.0% |
| Battery Discharge* | 0 | 0 | 0.0% | 0.0% |
| GAP | 25,000 | 10,738 | 4.9% | 5.5% |
| Imports | | 3,140 | | 1.6% |
| Load | | 193,573 | | 100.0% |
| Curtailment | | 14,077 | | 7.3% |
| Total Cost (\$/MWh) | Current | \$97.62 | Projected | \$72.61 |

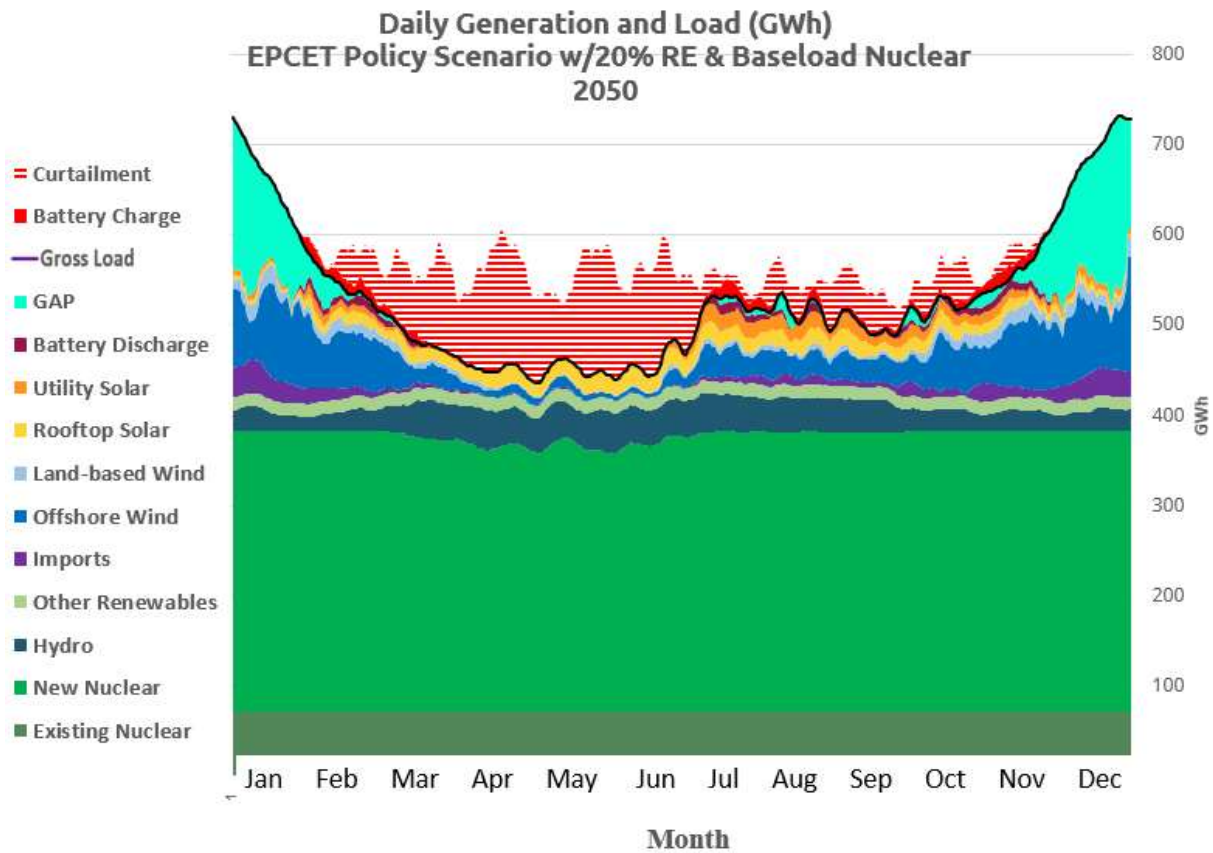
*Battery charging load is part of solar and wind output.

These computations assume a capital recovery factor – the portion of the initial capital investment for the facility that must be repaid each year – of 7%, which corresponds to an economic life of about 25 years. Nuclear plants are now believed to be able to remain in service for at least 80 years. In that case, the capital recovery factor would be 5%, and the cost of this scenario would be just 45% of the cost of the renewable-focused EPCET Policy Scenario (Figure 3.1 using current prices, and 59% of the cost using NREL projected prices).

A middle-ground alternative: Retain 20% of grid-based renewables, replacing the rest with baseload nuclear

We can consider intermediate plans as well, in which a portion of the renewables envisioned in the EPCET plan are installed, with the remainder replaced by baseload nuclear plants. As an example, Figure 4.2 shows a scenario with 20% of the grid renewables in EPCET, still far more than are in place today. In this scenario, the equivalent of seven Millstone facilities are built, with only rooftop solar installed at the level projected by ISO-NE. The cost is greater than the previous scenario, in which nuclear plants replaced all of the new grid-based renewables.

Figure 4.2 - EPCET Policy Scenario w/20% Renewable Energy & Baseload Nuclear



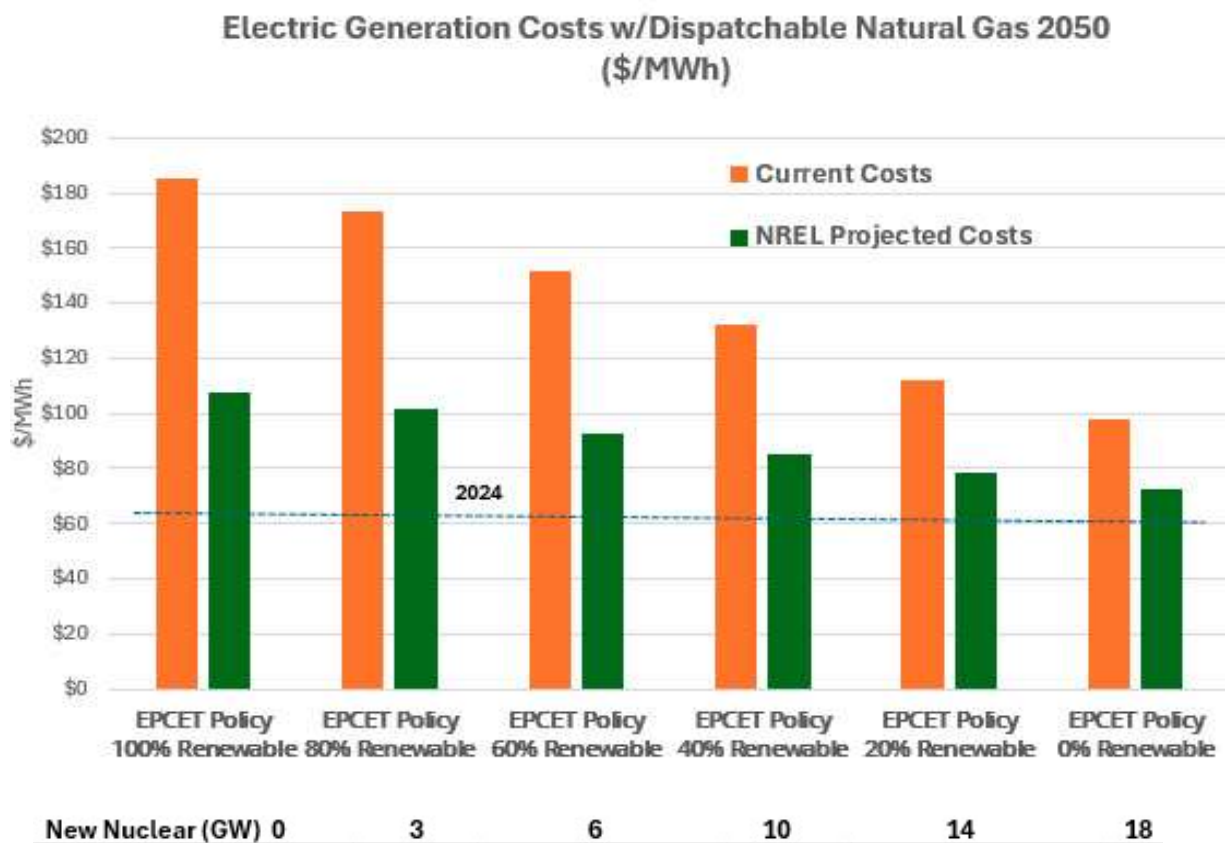
| Electricity Generation | | | | |
|---|----------------|-----------------|---------------------|----------------|
| EPCET Policy Scenario w/20% RE & Baseload Nuclear | | | | |
| 2050 | | | | |
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% |
| New Nuclear | 14,000 | 111,430 | 90.9% | 57.5% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% |
| Utility Solar | 5,500 | 3,290 | 6.8% | 1.7% |
| Land-based Wind | 1,500 | 2,867 | 21.8% | 1.5% |
| Offshore Wind | 6,880 | 14,748 | 24.5% | 7.6% |
| Battery Discharge* | 5,500 | 1,293 | 2.7% | 0.7% |
| GAP | 25,000 | 9,572 | 4.4% | 4.9% |
| Imports | | 3,540 | | 1.8% |
| Load | | 193,801 | | 100.0% |
| Curtailment | | 16,518 | | 8.5% |
| Total Cost (\$/MWh) | Current | \$112.41 | Projected | \$78.12 |

*Battery charging load is part of solar and wind output.

Introducing new nuclear power reduces the cost of decarbonization

Figure 4.3 below shows the cost of plans with fixed amounts of dispatchable natural gas but varying amounts of renewable and nuclear power (shown in GW below the graph) at current as well as projected prices. The more nuclear power is installed, the lower the cost. The steady, reliable output from nuclear reactors overcomes the apparent lower cost of solar and wind because their intermittence and variability require overbuilding and substantial backup. The cost figures used here are the best available, with the renewable costs coming from the DOE’s National Renewable Energy Laboratory and the nuclear costs a consensus from DOE’s Energy Information Administration, and NREL.²³ Actual nuclear costs would have to be 50% greater than these projections before the cost of any of the renewable scenario would be less than that of a nuclear-oriented plan.

Figure 4.3 – Comparing Costs of Renewable and Nuclear Plans Using Dispatchable Natural Gas



²³ Meta-Analysis of Advanced Nuclear Reactor Cost Estimations. INL 2025. <https://www.osti.gov/biblio/2371533>

Why does a plan based on renewables cost so much?

It is widely believed that renewables are much less expensive than any other energy source. The preceding examination of renewable-focused and nuclear-dominant scenarios shows this is incorrect. This leads to the following set of questions:

1. Why are renewables so expensive? The answer: Because they must be overbuilt and backed up by other, more reliable sources of power.
2. Why must renewables be overbuilt and backed up? Because they are variable and intermittent and often produce little or no power when it is needed.
3. Can adding more batteries eliminate the need for a dispatchable backup? No, batteries must be charged, requiring even more overbuilding and ever greater expense (See Appendix B).

5. Seeking a Dispatchable Emission-Free Resource to Fill the Gap

So far, this study has been discussing the sources on the grid which are fixed and non-dispatchable or which respond to external factors such as the weather (e.g., sunlight and wind) or the price (e.g., imports). We found, as did the New England planners, a large gap between what the renewables and batteries could provide and what will be needed to keep the lights on. This gap between supply and demand can be very large, especially in the winter or when the day is overcast or at night when the wind is not blowing and the batteries have been discharged. Without the added baseload nuclear, a backup was needed having a capacity nearly as large as the full load on the system; with the added nuclear, the gap is smaller but still quite substantial, especially if we expect to achieve expanded electrification of home heating and automobiles.

The demand on the grid varies moment to moment, as users of electricity turn their appliances on and off, elevators start and stop, and, of course, data centers consume large and varying amounts of power as computers seek answers to increasingly complex questions. As a consequence, every electric grid needs a flexible, firm source of power that is always available and is dispatchable, that is, one that can respond reliably and effectively to the rapid fluctuations in demand placed on the grid. Today, that role is primarily filled by burning natural gas to power turbine generators. However, though gas produces less emission of greenhouse gases than coal, it still conflicts with state decarbonization goals. Further, we should recognize that natural gas will not be available to meet our long-term energy needs. Studies of the remaining gas available

underground suggest that, by the end of this century, the economically recoverable reserves will be greatly diminished.²⁴

So, we need to determine what sources are clean, firm and dispatchable and can be used to fill that gap. Currently, natural gas plays that essential backup role, but use of such a fossil fuel is not consistent with New England's decarbonization objectives. The gap has to be filled by a reliable and flexible source that is free of greenhouse gas emissions. What can it be? As we have noted earlier, New England planners have been counting on some kind of zero-carbon or carbon-neutral fuel to fill the gap. These alternate fuels do not exist, though they may become available in the future with enough technological and industrial development.

One zero-carbon fuel might be hydrogen, produced by splitting water using electrically powered hydrolyzers.²⁵ Hydrogen can be used to drive gas turbines and, of course, will produce no carbon dioxide. However, as the smallest of all molecules, it is difficult to handle, to transport, or to store. Depending upon it to serve as an essential part of an electric grid will require creating a broad, expensive industrial network that doesn't exist now. Also, its use can lead, indirectly, to the creation of greenhouse gases in the atmosphere, so it can have negative consequences for climate change.²⁶

Using carbon-neutral hydrocarbons to fuel gas turbines is also a possibility. These would be artificial synthetic fuels created using carbon that had been deposited, through natural cyclic processes.²⁷ The production of such fuels using the century-old Fischer-Tropsch process²⁸ has been demonstrated using seawater,²⁹ plants,³⁰ and the air.³¹ However, this approach would require extensive industrial development which has not yet begun.

Nuclear power can serve as the required clean firm dispatchable source

Nuclear power is the only carbon-free technology which is capable of meeting the requirements for a firm and dispatchable source with an established industrial base and a long history of development. It offers the necessary reliability, flexibility, and scalability in the

²⁴ *Shale's Long Goodbye* <https://www.gorozen.com/commentaries/2025-q2>. *Potential Supply of Natural Gas in the United States* https://www.aga.org/wp-content/uploads/2025/09/Roberts_PGC_Press_Conference_2025-002.pdf. *How much natural gas does the United States have, and how long will it last?*

<https://www.eia.gov/tools/faqs/faq.php?id=58&t=8>

²⁵ <https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis>

²⁶ https://www.edf.org/sites/default/files/2024-02/H2WarmingEffectsFactSheet_FEB2024.pdf

²⁷ <https://www.pmel.noaa.gov/co2/story/Ocean+Carbon+Uptake>

²⁸ https://wikipedia.org/wiki/Fischer-Tropsch_process

²⁹ https://www.hydrogen.energy.gov/pdfs/review18/ia018_willauer_2018_p.pdf

³⁰ <https://www.sciencedirect.com/science/article/pii/S0306261921006486?via%3Dihub>

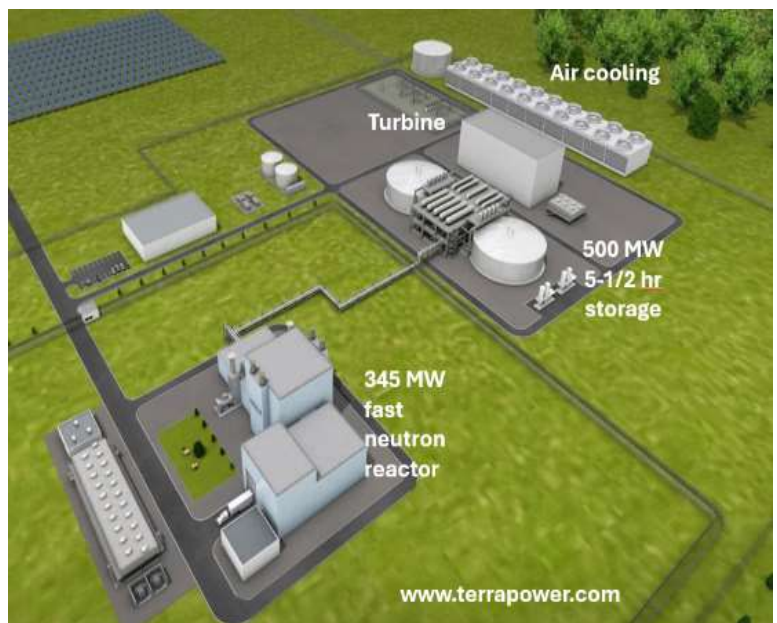
³¹ <https://news.berkeley.edu/2024/10/23/capturing-carbon-from-the-air-just-got-easier>

gigawatt-scale reactors now operating in the US and globally, but also in smaller reactors operating on submarines and ships for many decades and now under commercial development as small modular reactors (SMRs). Five of the New England states would, of course, have to lift their restrictions on the construction of new nuclear plants for this option to be exercised.

We usually think of nuclear plants as running steadily at a fixed power level – that is as always-on baseload – since they are connected directly to a steam-driven turbine generator. However, even these large reactors can be “load following” and, within limits, fully dispatchable.³² Their heat output can be varied, albeit slowly, and the steam they produce to drive generators can, if necessary, be diverted as needed to balance the demand. The individual units in multi-module small modular reactors (SMRs) can also be utilized as needed. In systems like the Terrapower Natrium, the power source is separated from the dispatchable steam-driven generator by the thermal energy storage. That way, the reactors can be operated at full-power full-time, their most efficient mode, while their electrical output is varied in accordance with the demand on the grid and any excess heat is simply “dumped” to the cooling fans.

A nuclear dispatchable emission-free resource (DEFER)

The Terrapower Natrium system combines a nuclear reactor with separate thermal energy storage.³³ It can supply 345 MW continuously and, for up to 5-1/2 hours, as much as 500 MW. Heat is resupplied from the sodium-cooled fast neutron reactor. Using technology originally developed in the Dept. of Energy’s Experimental Breeder Reactor (EBR-I and II), this first of its kind is now being installed in Wyoming.³⁴



³² *Nuclear is a Dispatchable Electricity Source*, Dietmar Detering.
<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA0F5C88B-0000-C521-AAAD-996DCC98AF0F%7D>

³³ <https://www.terrapower.com/our-work/natriumpower>

³⁴ https://en.wikipedia.org/wiki/Experimental_Breeder_Reactor_II

A nuclear DEFR can meet the need, but it is expensive

Figure 5.1 below shows the all-renewable EPCET Policy Scenario with a Sodium nuclear reactor and its thermal storage – referred to here as Flex Nuclear – serving as the required firm dispatchable source. This is a clean system which will keep the lights on and the data centers running. However, added to the cost of the renewables, much of whose output is curtailed, this is a system that is considerably more expensive than the original one (Figure 3.2) using gas-fired turbines as the gap-filler. There are several lower-cost alternatives.

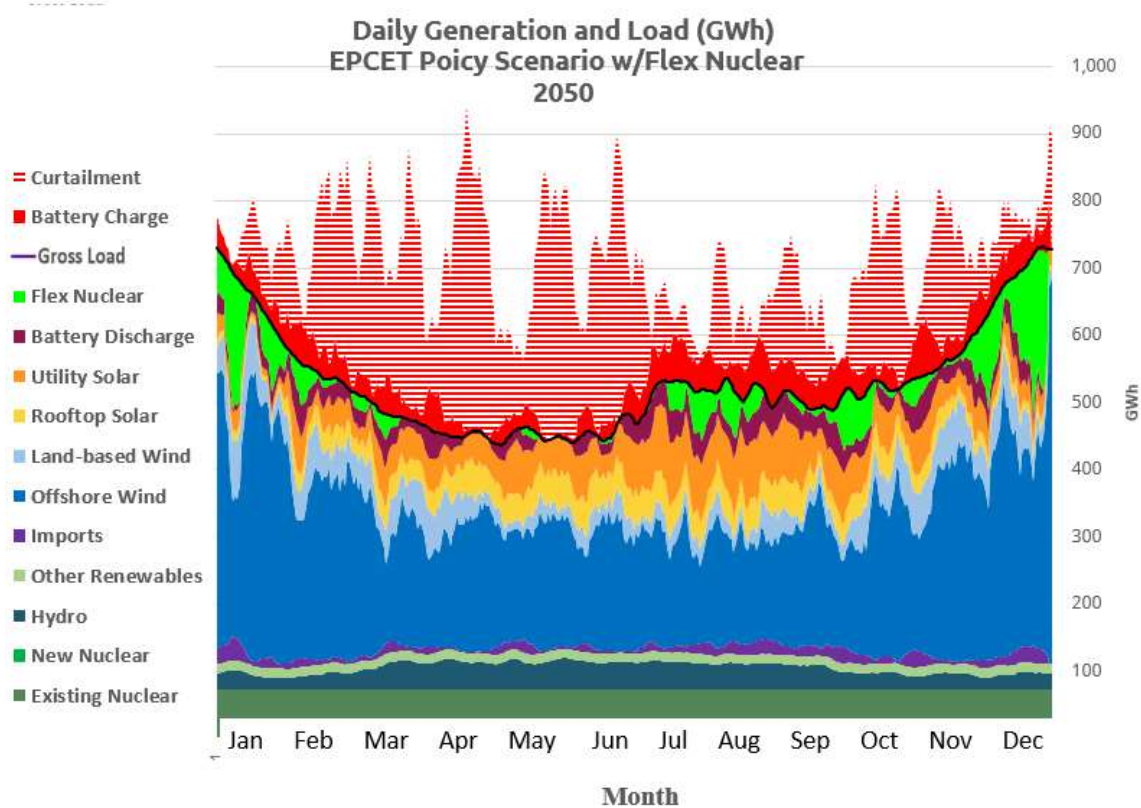
A better plan: Treat nuclear as *backbone* and as firm dispatchable resource

A very different plan, like that shown earlier in Figure 4.1, would replace most of the currently planned solar, wind, and batteries with a set of baseload nuclear reactors and add flex nuclear as the DEFR. This plan is shown in Figure 5.2. It would be far less environmentally destructive than the expansion of solar, wind, and batteries shown in Figure 5.1.³⁵ Further, it would be much less expensive. However, just one-fifth of the capacity of the flex nuclear would be used, making it a relatively inefficient use of nuclear power. However, when these plants are not producing electric power for the grid, they could produce hydrogen, carbon-neutral hydrocarbons, or electric power for export. This would make them as cost-efficient as a gas turbine.

Solar, wind, and batteries can be kept in the plan, as shown in Figure 5.3, with 20% of EPCET's renewables. However, this is more costly than the plan with no new renewables. As Figure 5.4 shows, with varying levels of renewables, including additional renewables will increase the cost (and environmental impact) without offering any positive value.

³⁵ Integrated Life-cycle Assessment of Electricity Sources (Figure 1), UNECE. <https://unece.org/documents/2022/08/integrated-life-cycle-assessment-electricity-sources>. Material Requirements to Phase Out Fossil Fuels with Renewables - Simon Michaux. https://tupa.gtk.fi/julkaisu/bulletin/bt_416.pdf

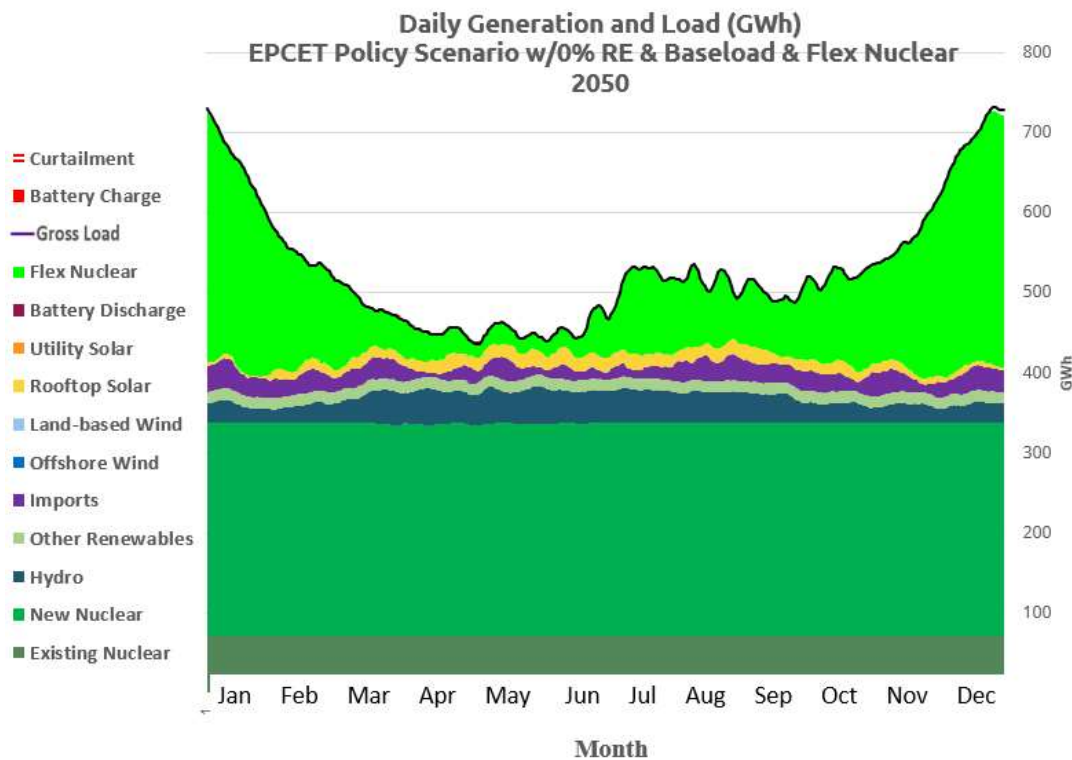
Figure 5.1 – EPCET Policy Scenario with 100% Renewable Energy & Flex Nuclear



| Electricity Generation EPCET Policy Scenario w/Flex Nuclear 2050 | | | | |
|--|-------------------------|---------------------------|---------------------|---------------|
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% |
| Utility Solar | 27,538 | 22,431 | 9.3% | 11.5% |
| Land-based Wind | 7,500 | 15,936 | 24.3% | 8.2% |
| Offshore Wind | 34,406 | 86,422 | 28.7% | 44.3% |
| Battery Discharge* | 27,500 | 9,399 | 3.9% | 4.8% |
| Flex Nuclear | 28,000 | 10,958 | 4.5% | 5.6% |
| Imports | | 4,212 | | 2.2% |
| Load | | 195,300 | | 100.0% |
| Curtailment | | 54,031 | | 27.7% |
| Total Cost (\$/MWh) | Current \$284.75 | Projected \$163.59 | | |

*Battery charging load is part of solar and wind output.

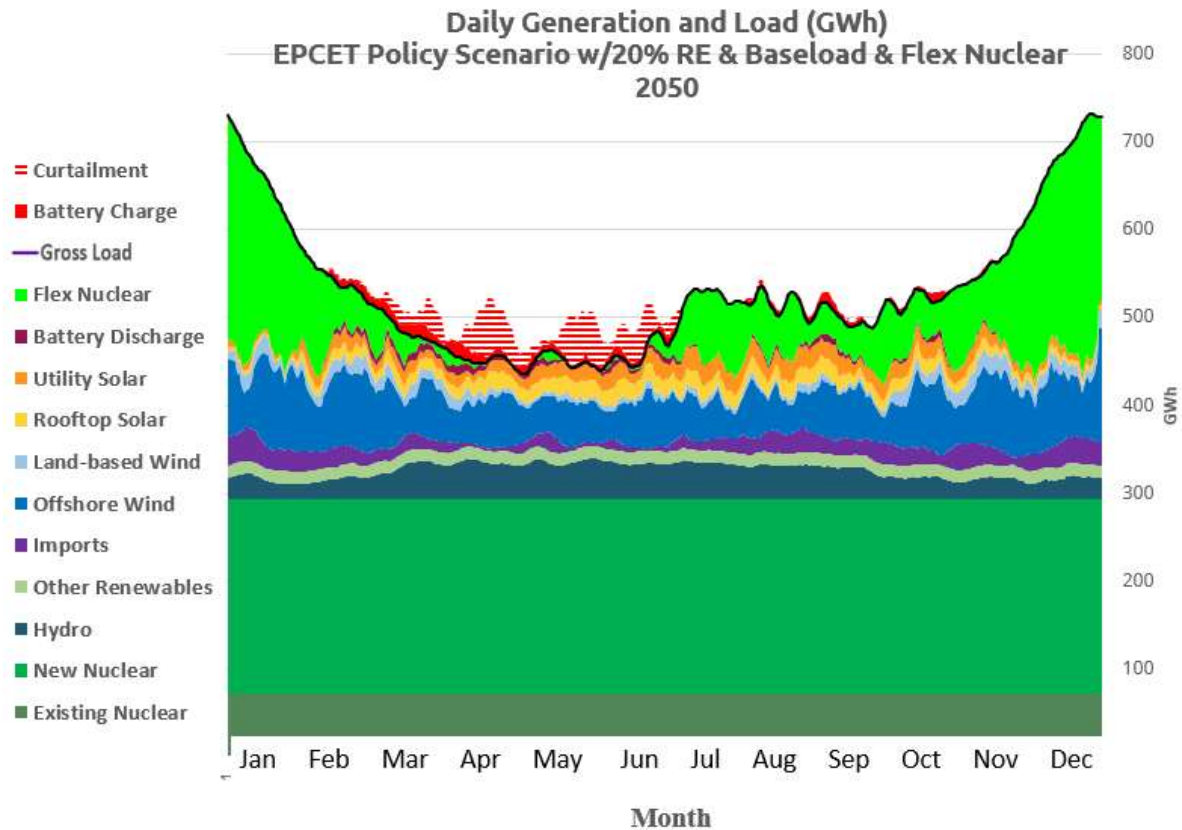
Figure 5.2 – EPCET Policy Scenario with 0% Renewable Energy & Baseload & Flex Nuclear



| Electricity Generation | | | | |
|--|-------------------------|---------------------------|----------------------------|---------------|
| EPCET Policy Scenario w/0% RE & Baseload & Flex Nuclear | | | | |
| 2050 | | | | |
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% |
| New Nuclear | 12,000 | 96,812 | 92.1% | 50.0% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% |
| Utility Solar | 0 | 0 | 0.0% | 0.0% |
| Land-based Wind | 0 | 0 | 0.0% | 0.0% |
| Offshore Wind | 0 | 0 | 0.0% | 0.0% |
| Battery Discharge* | 0 | 0 | 0.0% | 0.0% |
| Flex Nuclear | 23,000 | 40,715 | 20.2% | 21.0% |
| Imports | | 7,643 | | 3.9% |
| Load | | 193,523 | | 100.0% |
| Curtailment | | 133 | | 0.1% |
| Total Cost (\$/MWh) | Current \$157.40 | Projected \$101.65 | | |

*Battery charging load is part of solar and wind output.

Figure 5.3 – EPCET Policy Scenario with 20% Renewable Energy & Baseload & Flex Nuclear 2050



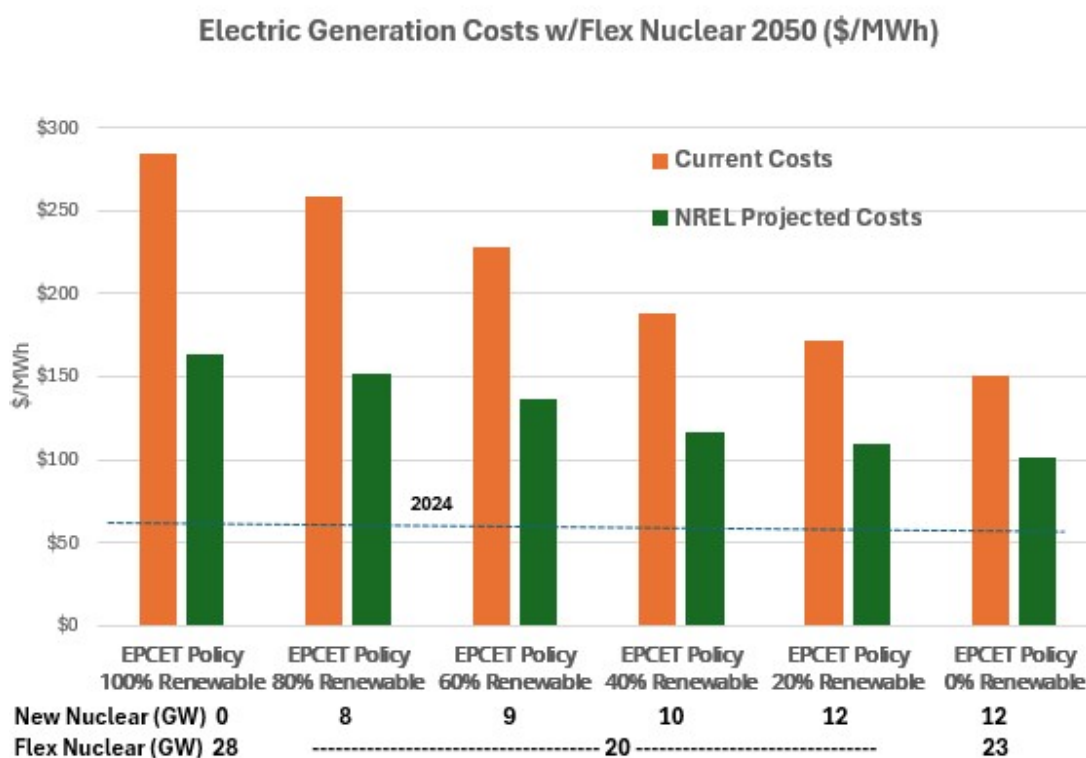
| Electricity Generation | | | | |
|---|-------------------------|-----------------|---------------------------|---------------|
| EPCET Policy Scenario w/20% RE & Baseload & Flex Nuclear 2050 | | | | |
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% |
| New Nuclear | 10,000 | 80,782 | 92.2% | 41.7% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% |
| Utility Solar | 5,500 | 5,927 | 12.3% | 3.1% |
| Land-based Wind | 1,500 | 3,904 | 29.7% | 2.0% |
| Offshore Wind | 6,880 | 22,562 | 37.4% | 11.6% |
| Battery Discharge* | 5,500 | 1,275 | 2.6% | 0.7% |
| Flex Nuclear | 25,000 | 25,954 | 11.9% | 13.4% |
| Imports | | 6,313 | | 3.3% |
| Load | | 193,797 | | 100.0% |
| Curtailment | | 3,363 | | 1.7% |
| Total Cost (\$/MWh) | Current \$187.04 | | Projected \$116.92 | |

*Battery charging load is part of solar and wind output.

Costs can remain stable with nuclear power

Figure 5.4 shows the estimated costs of electricity in 2050 of scenarios using flex nuclear instead of natural gas as the firm dispatchable resource, assuming current costs and NREL projected costs for 2050. Replacing the renewables with baseload nuclear reduces the cost, and the more nuclear is installed, the lower the cost. However, the cost is still greater than the cost of electricity today (See dashed line 2024 in Figure 5.4), or when gas serves as the dispatchable resource.

Figure 5.4 – Comparing Costs of Renewable and Nuclear Plan Using Dispatchable Nuclear



Why are these plans more costly than the earlier plans shown in Figure 4.3? Nuclear need not make a grid expensive; as we saw earlier, replacing much or all of the solar and wind with baseload nuclear substantially reduced the cost of electricity. Rather, in these scenarios, the flex nuclear plants are not being used very efficiently. They are generating 20% or less of the output they could be producing if all their output was being used; instead, much of the time, the storage tanks will just dump their excess heat. As a result, their cost to the system, per megawatt-hour, is significantly greater than the cost of the nuclear units running in always-on baseload mode.

Using flex nuclear plants to provide other essential decarbonization services

These powerful facilities could be put to use when they are not generating electricity for the grid. They might export power to other regions. They might be used to desalinate water. They might run electrolyzers to produce hydrogen for industrial applications. Or they might supply the heat and electricity needed to create carbon-neutral fuels that could power transcontinental aircraft, cargo ships, or long-distance trucking. If the flex nuclear plants in the 0% renewable case (Figure 5.2) were to be paid, say, 1.5 cents per kwh (\$15 per MWh) for supplying heat and electricity for any of these services (or perhaps others), they would receive revenue equivalent to \$59 for every MWh of electricity sent to the grid. Generation of electricity would then cost between \$42 and \$98 per MWh. (Recall that today's electric generating costs are \$63.20 per MWh.) Electricity in 2050 would cost approximately what it costs today, but it would be fully decarbonized.

Running nuclear reactors full-time to produce carbon-neutral synthetic fuels

Still another way of meeting the requirement for a clean dispatchable source of power, an approach which would require far fewer nuclear reactors, would be to use nuclear power to produce carbon-neutral synthetic fuels. These could then be burned in gas turbines that would generate the needed electric power. (This approach, using synthetic fuels to provide dispatchable power, was suggested by Massachusetts and ISO-NE planners but without specifying how the fuels would be produced.) Reactors running full-time ("baseload mode") could produce these fuels most efficiently.

Suppose the fuels could be produced with 50% efficiency, that is, 2 MWh of electricity (or heat- and electricity-equivalent) would yield fuel that, when burned in a modern combined cycle gas turbine, would generate 1 MWh of electricity. In that case, instead of the 23,000 MW of nuclear reactors needed in Figure 5.2, just 6,600 MW – three Millstones! – would be able to produce a year's fuel in that 0% renewable scenario. If the synthetic fuel cost no more than twice the current cost of natural gas, the cost of electricity would be \$98.58 (current prices) or \$73.57 (NREL projected prices), about what it costs today.

6. Conclusion: How to achieve an affordable carbon-free grid

We have shown how to build a reliable, fully decarbonized electric grid that will support economy-wide electrification. Our study, as well as the work of New England's grid planners, indicates that a strategy centered on large-scale expansion of intermittent renewables cannot achieve the goal of reliable emission-free power. By contrast, this can be accomplished if nuclear power is allowed a central role. Replacing much of the renewable buildup with baseload nuclear generation will reduce system costs and avoid the extensive land use, material requirements, transmission expansion, and environmental impacts that will accompany widespread deployment of wind and solar facilities.

A reliable carbon-free grid will also require a firm, reliable source of dispatchable, emission-free power that is available year-round. Because five New England states currently restrict new nuclear development, planners instead have assumed the future availability of renewable natural gas or carbon-neutral synthetic fuels – resources that do not now exist at even the developmental stage.

Dispatchable nuclear technologies can meet this need. When not required to meet regional electrical needs, these facilities could export power or produce carbon-neutral fuels for aviation, shipping, and other hard-to-electrify sectors. Thus, for New England to decarbonize in the most reliable, cost-effective, and environmentally protective manner, the states that currently restrict new nuclear installations should remove these limits and enable a realistic regional strategy that can achieve a workable carbon-free grid.

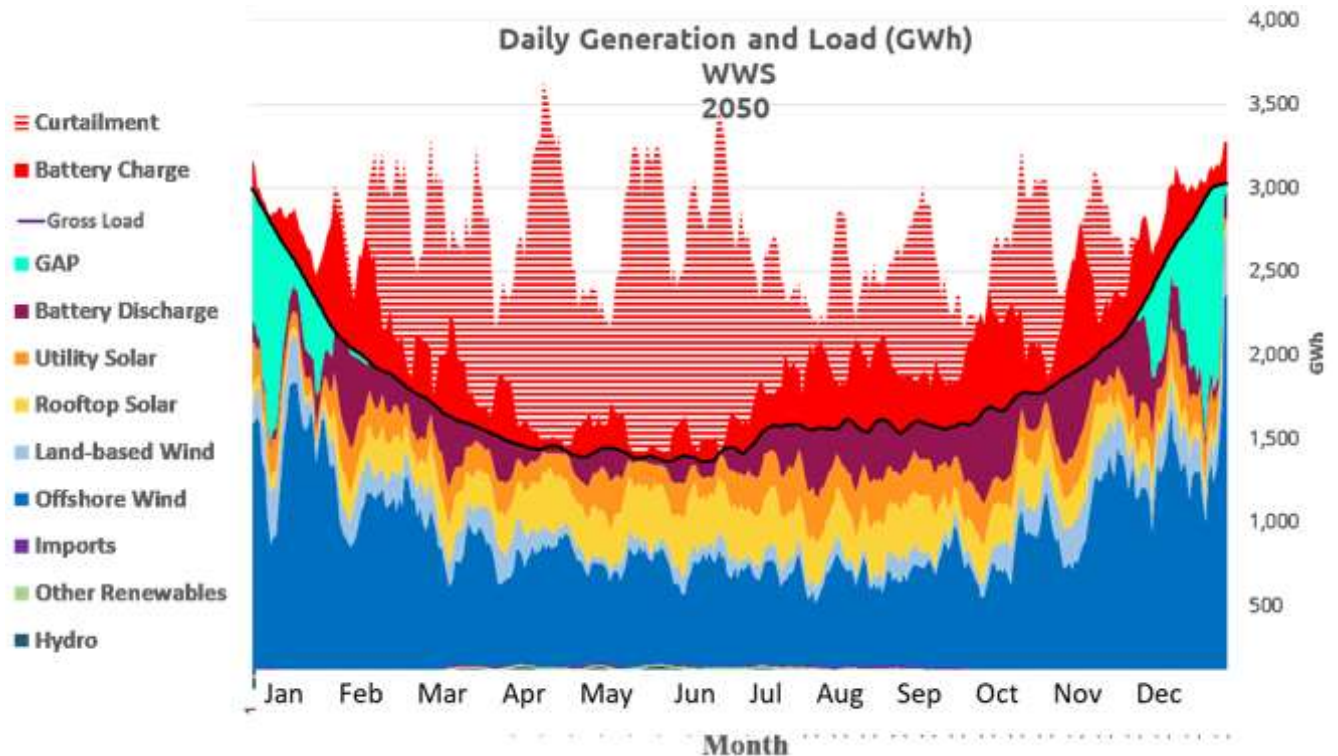
Policymakers also need to consider an energy source's environmental impact, using as few natural resources as possible and disturbing the natural environment as little as possible. This requires looking at the full life cycle of each option from mining and manufacturing to construction and installation, operation, and waste production.

Nuclear power has a distinct advantage in all these categories due to its high energy density. A small volume of nuclear fuel produces a large quantity of energy and, consequently, a very small volume of waste that can be easily contained in storage facilities. Further, nuclear's steady output avoids the massive overbuilding required with intermittent renewables. Solar and wind installations have a 20- to 30-year lifespan and will need to be replaced three or four times within the lifespan of a nuclear plant. Hence, nuclear power is also the option that can best preserve our mineral resources, forests and wild spaces.

Appendix A

100% Renewable Plan: Wind, Water, Solar (WWS)

In an extended series of papers³⁶, Mark Jacobson of Stanford University and his colleagues provide a plan involving just wind, water, and solar power to meet all energy needs for the New England and New York region.³⁷ Their plan projects the expected average electric load (GW) in 2050 and the necessary capacity (GW) of each of the solar and wind resources and batteries. The plan uses a large amount of solar and wind resources, many of which are curtailed (shut down) to avoid overloading the grid. During at least 50 days each year, this plan would experience blackouts (shown here in aqua). In addition, it would cost over three times what is now spent per MWh for electricity. (See datasheet in Appendix D for detailed quantitative results).



³⁶ <https://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-USA.html>

³⁷ <https://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-USA.html>

| Electricity Generation WWS 2050 | | | | |
|---------------------------------------|------------------|--------------------|------------------------|-----------------|
| Energy Source | Capacity (MW) | Output (GWh/yr) | Capacity Factor (%) | % Load |
| Hydro | 12,000 | 35,456 | 33.7% | 5.3% |
| Other Renewables | 763 | 5,210 | 78.0% | 0.8% |
| Rooftop Solar | 67,900 | 82,729 | 13.9% | 12.3% |
| Utility Solar | 182,000 | 117,731 | 7.4% | 17.4% |
| Land-based Wind | 24,900 | 55,835 | 25.6% | 8.3% |
| Offshore Wind | 125,000 | 333,221 | 30.4% | 49.4% |
| Battery Discharge* | 600,000 | 76,885 | 1.5% | 11.4% |
| GAP | 130,000 | 40,457 | 3.6% | 6.0% |
| Imports | | 4,435 | | 0.7% |
| Load | | 675,073 | | 100.0% |
| Curtailement | | 236,136 | | 35.0% |
| Total Cost (\$/MWh) | Current | \$369.59 | Projected | \$205.98 |

This plan will not work without the addition of a dispatchable source with a capacity that is nearly as large as the expected peak load in the winter. Why does it appear to work so that it can be applied to 50 states and 145 countries?³⁸ It is because the weather model used by this group does not use real solar and wind data. Rather, to supply these essential inputs to its energy calculations, it relies on a global atmospheric model designed in the 1990s to describe the circulation of air pollution.³⁹ Real weather is highly variable and random, unlike the output of the Jacobson atmospheric model, which lacks those essential characteristics. Further, any real electric grid requires a large, reliable, dispatchable, highly variable source; that essential component is not available in the Jacobson WWS plan.

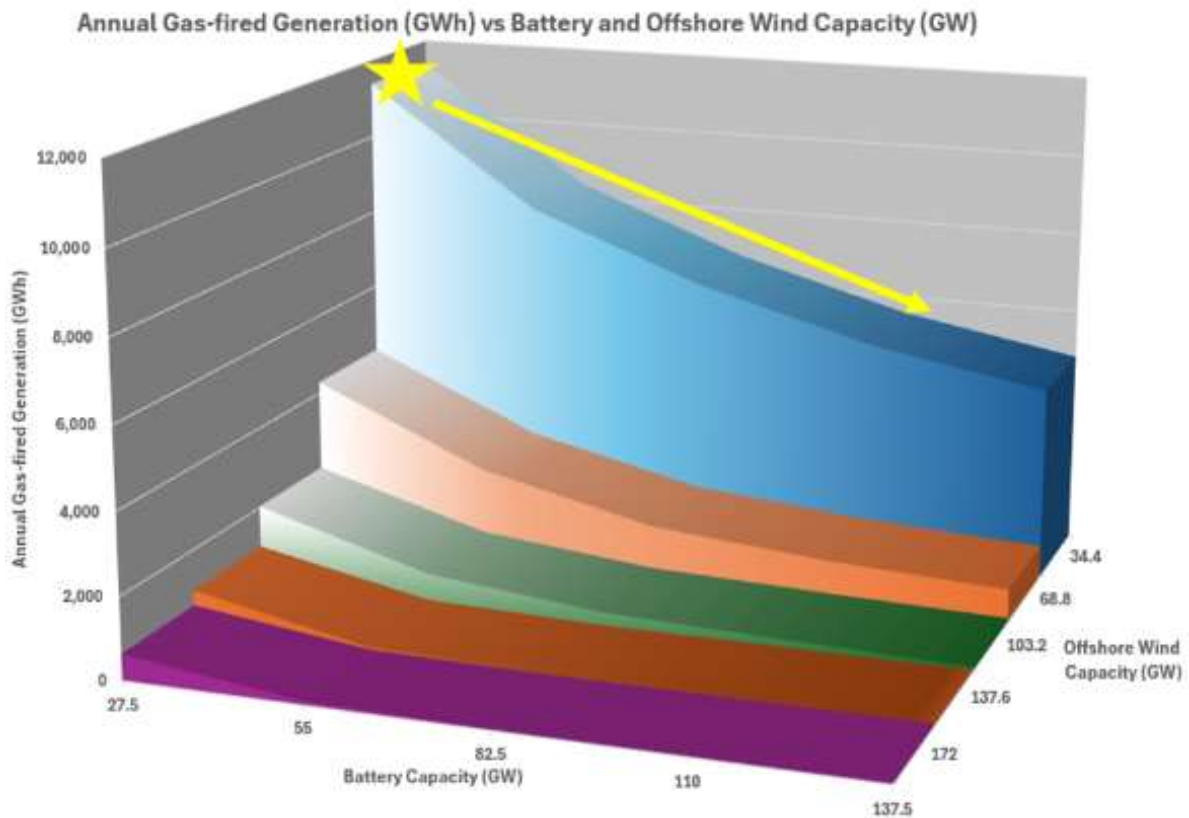
³⁸ M.Z.Jacobson et al, Low-cost solutions to global warming, air pollution, and energy insecurity for 145 countries, *Energy & Environmental Science*, 2015. <https://doi.org/1.1039/d2ee00722c>.

³⁹ M.Z.Jacobson, History of, Processes in, and Numerical Techniques in GATOR-GCMOM, <http://www.stanford.edu/group/efmh/jacobson/GATOR/index.html>

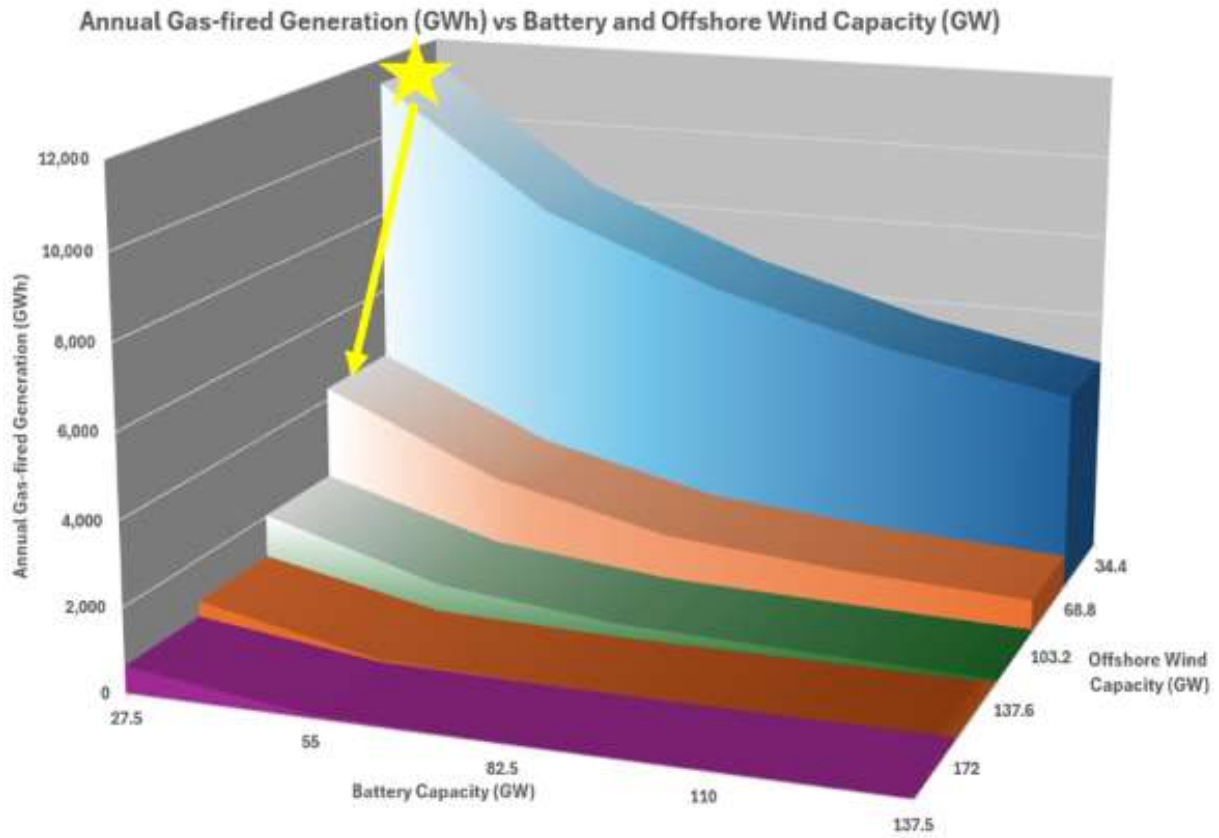
Appendix B

Can additional battery storage replace the burning of gas?

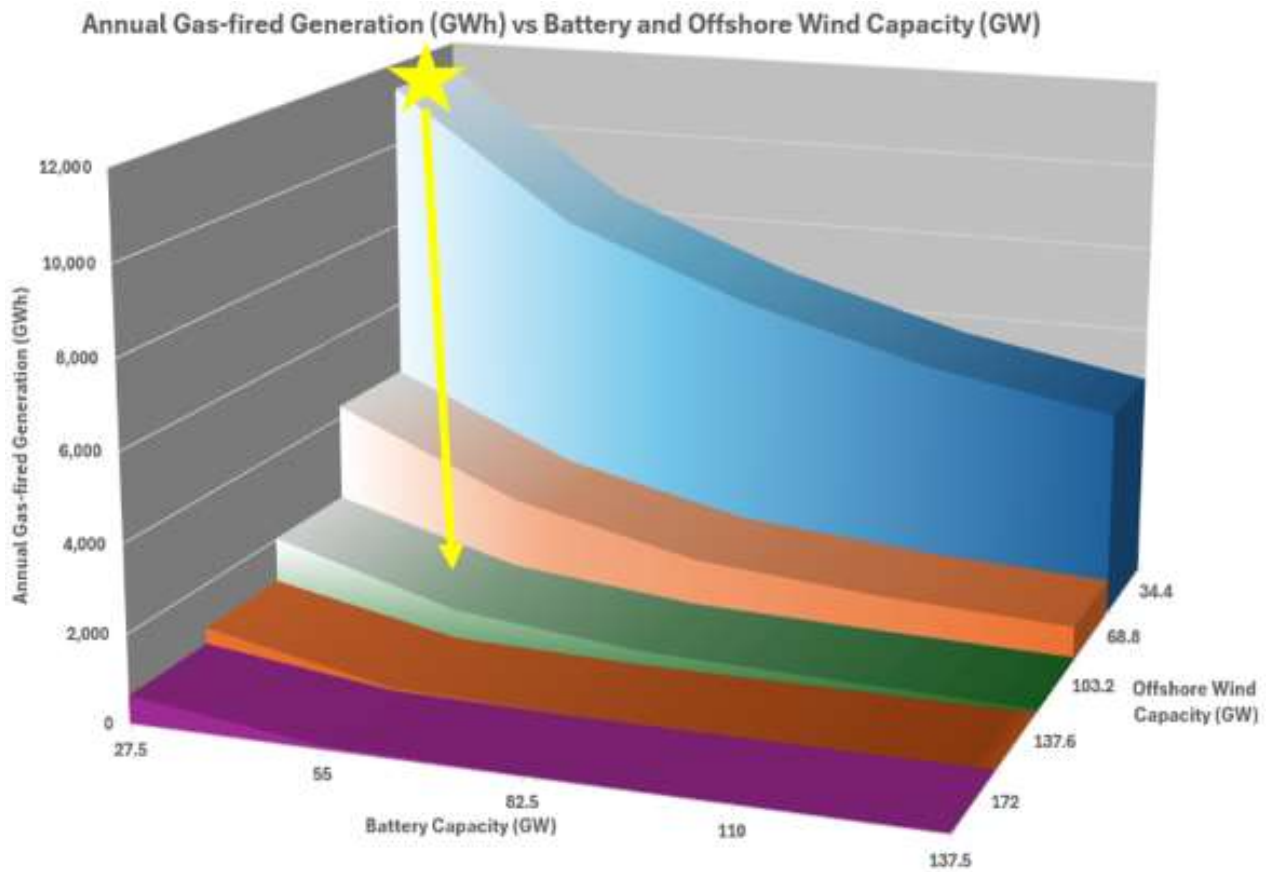
Some renewable advocates suggest that adding battery storage will eliminate the need for the burning of gas. HELGA was run with 25 cases for the EPCET Policy Scenario to see the effect of additional storage and offshore wind. The figures below show the effect of different amounts of storage (front axis), along with added offshore wind (side axis) to charge the batteries. The “star” shows the initial high gas usage, while the arrow shows the slow decline in gas usage as additional storage is added. As the figure shows, simply adding storage won’t reduce gas generation very much because there isn’t enough excess wind power to charge the extra batteries.



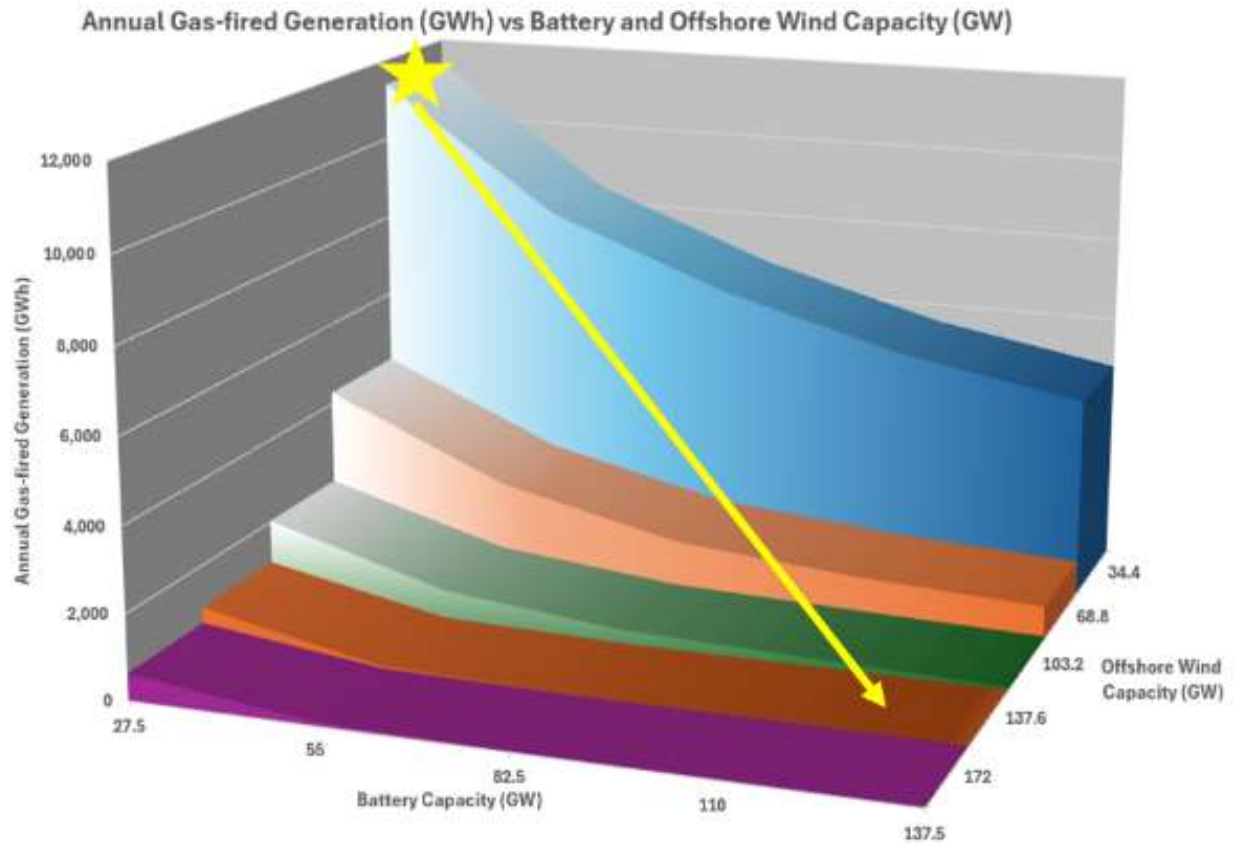
Doubling the amount of wind capacity enables the existing batteries to be used more fully. Gas generation is halved but is still substantial.



Adding more storage, along with still more wind capacity, reduces gas generation still further, by a smaller amount.



Finally, adding a great deal more storage, along with still more wind capacity, finally reduces gas generation to a negligible level – but the cost will clearly be unacceptable. Gas is still burned in this renewable-focused plan.



Appendix C

Hourly ELectric Grid Analysis (HELGA) Methodology

In this model, each type of energy source is dispatched hourly to address electric loads, taking into account inter-regional power purchases and sales. CO₂ emissions (if any), energy pricing, and the occurrence of surplus energy each hour from excessive non-dispatchable generation is also calculated.

Model inputs include hourly data for loads, solar generation, wind generation, hydro generation, and power exchange with other regions. The assumptions and methods used in the model are as follows:

Power generation is represented in these simplified categories: behind the meter rooftop and grid-connected utility solar, land-based and offshore wind, hydroelectric, nuclear, battery storage, and a series of possible dispatchable sources, especially gas-fired combined-cycle and simple-cycle plants. Existing nameplate capacities are taken from ISO-NE publications, while actual energy supplied is based on 2024 ISO-NE data.

Total system loads are estimated using 2024 data from Independent System Operator of New England (ISO-NE), which operates the region's electric grid. Projections of current demand, as well as the new demand from electric vehicles (EVs) and the electrification of buildings, are drawn from forecasts developed by the Massachusetts Executive Office of Energy and Environmental Affairs and ISO-NE.

Hourly generation from solar and land-based wind is scaled up based on the distribution of 2024 hourly output data for these sources. Hourly load shapes are estimated by reviewing hourly data for weekend/holidays and weekdays. Maximum and minimum daily loads are adjusted weekly based on historic data to account for seasonal variation and adjusted annually based on load growth projected by ISO-NE. Purchases from Canada and other states are modeled based on 2024 actual hourly data.

The maximum capacity of solar and wind facilities reflects the distribution of generators and the likelihood that they can operate at the same time. These values are different from nameplate capacity which represents the output of a single unit at a specified point, used to calculate installation cost. Maximum capacity is derived from evaluating actual generating data

in 2024 from ISO-NE. Until actual data is available for offshore wind installations, offshore wind is assumed to have the same relationship of maximum regional output to nameplate capacity as land-based wind.

Capacity factors – the fraction of the potential output of a source that is actually produced during the year – are not assumed inputs but are outputs calculated by the model, based upon the weather and the behavior of the grid.

The Dispatchable Emission-Free Resource is modeled using the characteristics of the TerraPower Natrium small modular reactor⁴⁰.

Battery storage is modeled by assuming the batteries are charged when there is more inflexible power from hydropower, nuclear, grid-connected solar, and wind than is needed to meet demand. The DEFR is not used to charge batteries. The batteries are discharged when the load on the grid is greater than can be provided by those ongoing inflexible sources.

Hourly loads and source dispatch are determined for each day of the year. Hourly load patterns are modeled based on 2024 data available from ISO-NE. Hourly load shapes are selected for workdays and for non-work holiday/weekend days and adjusted weekly for seasonal changes. ISO-NE reports estimated generation from behind-the-meter solar, even though it occurs on the customer side of the grid. Behind-the-meter solar currently represents the majority of solar electric generation capacity, but that will change as plans proceed.

Each source is dispatched in turn to meet the load, as follows: behind-the-meter solar is introduced first, leaving the remaining load to be served by the various sources connected to the grid. Purchases from neighboring states and Canada are added. Existing nuclear plant output is added as “must-run” capacity. Hydroelectric generation is added. Output from grid-connected solar plus onshore and offshore wind generation are then added, taking into account their hourly variations as described above.

Three percent of the maximum annual load is set aside for system control by gas-fired combined-cycle plants or battery discharge, representing spinning reserve and other ancillary grid services. This is required even when there are curtailments of solar and wind generation.

⁴⁰ <https://www.terrapower.com/our-work/natriumpower>

When there is unmet load remaining after the non-dispatchable sources have been included, the batteries are called on to discharge up to their ability. If unmet load still remains, then the DEFR is used to supply the remaining load. In the EPCET plan, the DEFR is assumed to be gas-fired turbines.

Curtailments occur when total non-dispatchable generation exceeds the load requirements. When there is insufficient load to use all possible solar and wind generation, purchases from other states are reduced or eliminated. Then curtailments are assigned in random order to offshore wind, onshore wind, and grid-connected solar, but not to behind-the-meter (BTM) solar, which is not controlled by the grid operator.

The model uses current dollars so that the effects of future inflation do not confuse the analysis. Costs of energy sources are estimated from a variety of NREL's Annual Technology Baseline. The prices used in the scenarios reported here are shown in the Datasheets in Appendix D. The total in-region generation cost of electricity is the weighted average of annual generation sources. The cost for each generation source includes fixed and variable operation and maintenance (O&M) cost, fuel cost, and capital recovery.

This study does not provide energy generator revenues, as the breakdown between energy market income vs. revenue from resource adequacy and other auctions operated by ISO-NE is not analyzed. The actual revenue sources depend upon varying arrangements for tax subsidies and other mechanisms for shifting costs from, and among, ratepayers, so this data would be too uncertain to be meaningful.

Limitations of the Current Model

The model used here, while it shows the principal properties and requirements for the future grid, has significant limitations. Among these are:

- This model treats the state's grid as a single unit without transmission constraints, whereas, in practice, there are significant barriers to the flow of power between areas of the region. The model also does not reflect transmission upgrade costs that will be required with economy-wide electrification, especially if widely distributed solar and wind facilities are expanded as envisioned in the region's current plans.

- Our model does not reflect the additional reserve requirements imposed by state and federal law.
- This study does not explore the wide range of possible future costs that seem likely for both renewable and nuclear resources, as well as for possible hydrogen options.
- The vast majority of nuclear reactor downtime is for scheduled maintenance and refueling. Routinely, such downtime is placed during periods of predicted low demand, currently in the spring and fall. While our model represents nuclear generation as flat throughout the year at a reduced capacity factor, full nuclear capacity should be available through the entire winter, the season of peak future demand. Incorporating this into the model would reduce the DEFR capacity needed.
- The chosen nuclear DEFR in our model, the Terrapower Sodium system, drops from 500 MW to 345 MW output capacity when its thermal storage is depleted. Having a DEFR with maximum capacity always available, perhaps accompanied by batteries, might be more cost-effective.

Appendix D

Datasheets

| | |
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New England 2024 (Figure 2.10)

| Year: 2024 | | | | | Current Costs | | | | | | GHG | | |
|---|---------------|---------------------|---------------------|---------------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|--------------------------|--------------------------|-------------|
| Generation Summary | | | | | | | | | | | | | |
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | CO2 Emissions (Mtons/yr) | | |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 22.8% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 | | | |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | | | |
| Hydro | 2,766 | 8,173 | 33.7% | 7.0% | | \$ 14.82 | \$ 1.48 | | | \$ 16.30 | | | |
| Other Renewables | 763 | 5,210 | 78.0% | 4.5% | | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 | | | |
| Rooftop Solar | 2,493 | 3,037 | 13.9% | 2.6% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 | | | |
| Utility Solar | 1,247 | 1,519 | 13.9% | 1.3% | \$ 1,500 | \$ 18.06 | \$ - | \$ - | \$ 86.18 | \$ 104.24 | | | |
| Land-based Wind | 1,253 | 3,521 | 32.1% | 3.0% | \$ 1,650 | \$ 11.39 | \$ - | \$ - | \$ 41.10 | \$ 52.49 | | | |
| Offshore Wind | 0 | 0 | 0.0% | 0.0% | \$ 6,500 | \$ 24.93 | \$ - | \$ - | \$ 126.05 | \$ 150.98 | | | |
| SubTotal | 11,848 | 47,939 | 46.2% | 41.3% | | \$ 9.75 | \$ 1.48 | \$ 2.26 | \$ 18.07 | \$ 31.56 | 0.0 | | |
| * Battery charging included in solar and wind generation. | | | | | | | | | | | | | |
| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | CO2 Emissions (Mtons/yr) | | |
| Battery Discharge | 160 | 0 | 0.0% | 0.0% | \$ 2,080 | \$ - | \$ - | \$ - | \$ - | \$ - | | | |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | | | |
| Hydrogen Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | |
| Gas | 30,000 | 60,019 | 22.8% | 51.7% | \$ 1,500 | 16.99 | 2.00 | 17.00 | 52.48 | 88.48 | 27.0 | | |
| Oil | 5,732 | 0 | 0.0% | 0.0% | \$ 1,257 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | | |
| Coal | 358 | 0 | 0.0% | 0.0% | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.0 | | |
| SubTotal | 36,250 | 60,019 | 18.9% | 51.7% | | \$ 16.99 | \$ 2.00 | \$ 17.00 | \$ 52.48 | \$ 88.48 | 27.0 | | |
| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | | | | | | | CO2 Emissions (Mtons/yr) | | |
| Total | 48,098 | 107,958 | 25.6% | 92.9% | | \$ 13.78 | \$ 1.77 | \$ 10.45 | \$ 37.20 | \$ 63.20 | 27.0 | | |
| <i>Regional Purchases</i> | | | Generation (GWh/yr) | % Total Load | | | | | | | CO2 Emissions (Mtons/yr) | | |
| Imports | | | 8,221 | 7.1% | | | | | | \$ 63.20 | | | |
| | | | | Total Load (GWh/yr) | Peak Load (GW) | | | | | Total Expenditure (\$B) | Total Cost (\$/MWh) | CO2 Emissions (Mtons/yr) | |
| | | | | 116,179 | 24 | | | | | | \$7.3 | \$ 63.20 | 27.0 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 366 |
| Days Batteries Discharged | 0 |
| Days Batteries Not Fully Charged | 366 |

** Firm sources = gas, coal, oil, flex nuclear

| | | % Total Load | % of Grid Renewables |
|-------------------------|---|--------------|----------------------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 0 | 0.0% | 0.0% |
| New Nuclear Curtailment | 0 | 0.0% | |

WWS (Appendix A)

| WWS Year: 2050 | | | | | Current Costs | | | | | |
|---|------------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|---|
| Generation Summary | | | | | Capital Cost | Fixed O&M | Var O&M | Fuel Cost | Capital Recovery | In-Region Generation Cost |
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | (\$/kw) | (\$/MWh) | (\$/MWh) | (\$/MWh) | (\$/MWh) | (\$/MWh) |
| Existing Nuclear | - | - | 0.0% | 0.0% | \$ 141 | \$ - | \$ 1.22 | \$ 4.09 | \$ - | \$ 5.31 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 12,000 | 35,456 | 33.7% | 5.3% | | \$ 14.82 | \$ 1.48 | | | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 0.8% | | \$ 19.27 | \$ 5.06 | | | \$ 24.33 |
| Rooftop Solar | 67,900 | 82,729 | 13.9% | 12.3% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | 182,000 | 117,731 | 7.4% | 17.4% | \$ 1,500 | \$ 34.01 | \$ - | \$ - | \$ 162.32 | \$ 196.33 |
| Land-based Wind | 24,900 | 55,835 | 25.6% | 8.3% | \$ 1,650 | \$ 14.27 | \$ - | \$ - | \$ 51.51 | \$ 65.78 |
| Offshore Wind | 125,000 | 333,221 | 30.4% | 49.4% | \$ 6,500 | \$ 33.76 | \$ - | \$ - | \$ 170.68 | \$ 204.44 |
| SubTotal | 412,563 | 630,181 | 17.4% | 93.4% | | \$ 29.70 | \$ 0.13 | \$ - | \$ 149.28 | \$ 179.10 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 600,000 | 76,885 | 1.5% | 11.4% | \$ 2,080 | \$ 374.59 | \$ - | \$ - | \$ 1,136.24 | \$ 1,510.83 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 130,000 | 40,457 | 3.6% | 6.0% | \$ 1,500 | 109.25 | 2.00 | 17.00 | 337.40 | 465.65 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| SubTotal | 730,000 | 40,457 | 0.6% | 6.0% | | \$ 283.10 | \$ 0.69 | \$ 5.86 | \$ 860.82 | \$ 1,150.47 |
| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Total | 1,142,563 | 670,637 | 6.7% | 99.3% | | \$ 44.98 | \$ 0.16 | \$ 0.35 | \$ 192.20 | \$ 369.59 |
| <i>Regional Purchases</i> | | Generation (GWh/yr) | | % Total Load | | | | | | Import Purchase Cost (\$/MWh) |
| Imports | | 4,435 | | 0.7% | | | | | | \$ 369.59 |
| Total | | 675,073 | | | | | | | | Total Cost (\$/MWh) \$ 369.59 |

| Generation Summary | | | | | Projected Costs | | | | | |
|---|------------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|---|
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | - | - | 0.0% | 0.0% | \$ 140 | \$ - | \$ 1.22 | \$ 4.09 | \$ - | \$ 5.31 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 12,000 | 35,456 | 33.7% | 5.3% | | \$ 14.82 | \$ 1.48 | | | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 0.8% | | \$ 19.27 | \$ 5.06 | | | \$ 24.33 |
| Rooftop Solar | 67,900 | 82,729 | 13.9% | 12.3% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | 182,000 | 117,731 | 7.4% | 17.4% | \$ 700 | \$ 21.64 | \$ - | \$ - | \$ 75.75 | \$ 97.39 |
| Land-based Wind | 24,900 | 55,835 | 25.6% | 8.3% | \$ 1,100 | \$ 11.59 | \$ - | \$ - | \$ 34.34 | \$ 45.93 |
| Offshore Wind | 125,000 | 333,221 | 30.4% | 49.4% | \$ 3,500 | \$ 26.26 | \$ - | \$ - | \$ 91.91 | \$ 118.16 |
| SubTotal | 412,563 | 630,181 | 17.4% | 93.4% | | \$ 21.78 | \$ 0.13 | \$ - | \$ 74.84 | \$ 96.75 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 600,000 | 76,885 | 1.5% | 11.4% | \$ 1,140 | \$ 195.10 | \$ - | \$ - | \$ 622.75 | \$ 817.84 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 130,000 | 40,457 | 3.6% | 6.0% | \$ 1,200 | \$ 64.27 | \$ 2.00 | \$ 17.00 | \$ 269.92 | \$ 353.18 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 730,000 | 40,457 | 0.6% | 6.0% | | \$ 149.99 | \$ 0.69 | \$ 5.86 | \$ 501.10 | \$ 657.64 |
| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Total | 1,142,563 | 670,637 | 6.7% | 99.3% | | \$ 29.51 | \$ 0.16 | \$ 0.35 | \$ 100.56 | \$ 205.98 |
| <i>Regional Purchases</i> | | Generation (GWh/yr) | | % Total Load | | | | | | Import Cost (\$/MWh) |
| Imports | | 4,435 | | 0.7% | | | | | | \$ 205.98 |
| Total | | 675,073 | | | | | | | | Total Cost (\$/MWh) \$ 205.98 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 51 |
| Days Batteries Discharged | 290 |
| Days Batteries Not Fully Charged | 148 |

** Firm sources = gas, coal, oil, flex nuclear

| | GWh/yr | % Total Load | % of Grid Renewables |
|-------------------------|---------|--------------|----------------------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 236,136 | 35.0% | 26.0% |
| New Nuclear Curtailment | 0 | 0.0% | |

MA Full Electrification (Figure 3.1)

| MA Full Electrification Year: 2050 | | | | | Current Costs | | | | | |
|---|----------------|---------------------|---------------------|--------------|--------------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Generation Summary | | | | | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | | | | | | |
| Existing Nuclear | 3,350 | 26,669 | 90.9% | 9.2% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 3,991 | 11,792 | 33.7% | 4.0% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 3,600 | 24,583 | 78.0% | 8.4% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 49,000 | 59,701 | 13.9% | 20.5% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | 24,000 | 13,339 | 6.3% | 4.6% | \$ 1,500 | \$ 39.58 | \$ - | \$ - | \$ 188.93 | \$ 228.51 |
| Land-based Wind | 15,000 | 31,125 | 23.7% | 10.7% | \$ 1,650 | \$ 15.42 | \$ - | \$ - | \$ 55.66 | \$ 71.08 |
| Offshore Wind | 38,000 | 95,785 | 28.8% | 32.9% | \$ 6,500 | \$ 35.70 | \$ - | \$ - | \$ 180.51 | \$ 216.21 |
| SubTotal | 136,941 | 262,994 | 21.9% | 90.3% | \$ 25.29 | \$ 0.66 | \$ 0.41 | \$ 123.77 | \$ 150.14 | \$ 150.14 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 26,600 | 13,201 | 5.7% | 4.5% | \$ 2,080 | \$ 96.72 | \$ - | \$ - | \$ 293.38 | \$ 390.10 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydrogen Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 40,000 | 23,919 | 6.8% | 8.2% | \$ 1,500 | \$ 56.86 | \$ 2.00 | \$ 17.00 | \$ 175.59 | \$ 251.45 |
| Oil | 340 | 1 | 0.0% | 0.0% | \$ 1,257 | \$ 9,068.36 | \$ 2.00 | \$ 169.00 | \$ 0.00 | \$ 9,239.36 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 66,940 | 23,919 | 4.1% | 8.2% | \$ 71.22 | \$ 1.29 | \$ 10.96 | \$ 217.48 | \$ 300.94 | \$ 300.94 |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 203,881 | 286,914 | 16.1% | 98.5% | \$ 29.12 | \$ 0.72 | \$ 1.29 | \$ 131.58 | \$ 176.56 | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Imports | | 4,456 | | 1.5% | | | | | \$ 176.56 | |
| Total | | 291,370 | | 54 | | | | | \$ 176.56 | |
| | | | | | Total Expenditure (\$B) | | | | | Total Cost (\$/MWh) |
| | | | | | \$51.4 | | | | | \$ 176.56 |

| Generation Summary | | | | | Projected Costs | | | | | |
|---|----------------|---------------------|---------------------|--------------|--------------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,350 | 26,669 | 90.9% | 9.2% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 3,991 | 11,792 | 33.7% | 4.0% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 3,600 | 24,583 | 78.0% | 8.4% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 49,000 | 59,701 | 13.9% | 20.5% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | 24,000 | 13,339 | 6.3% | 4.6% | \$ 700 | \$ 25.19 | \$ - | \$ - | \$ 88.17 | \$ 113.36 |
| Land-based Wind | 15,000 | 31,125 | 23.7% | 10.7% | \$ 1,100 | \$ 12.53 | \$ - | \$ - | \$ 37.11 | \$ 49.64 |
| Offshore Wind | 38,000 | 95,785 | 28.8% | 32.9% | \$ 3,500 | \$ 27.77 | \$ - | \$ - | \$ 97.20 | \$ 124.97 |
| SubTotal | 136,941 | 262,994 | 21.9% | 90.3% | \$ 18.90 | \$ 0.66 | \$ 0.41 | \$ 60.04 | \$ 80.02 | \$ 80.02 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 26,600 | 13,201 | 5.7% | 4.5% | \$ 1,140 | \$ 50.37 | \$ - | \$ - | \$ 160.80 | \$ 211.17 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydrogen Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 40,000 | 23,919 | 6.8% | 8.2% | \$ 1,200 | \$ 33.45 | \$ 2.00 | \$ 17.00 | \$ 140.48 | \$ 192.92 |
| Oil | 340 | 1 | 0.0% | 0.0% | \$ 1,257 | \$ 0.00 | \$ 2.00 | \$ 169.00 | \$ 0.00 | \$ 171.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 66,940 | 23,919 | 4.1% | 8.2% | \$ 39.47 | \$ 1.29 | \$ 10.96 | \$ 147.70 | \$ 199.41 | \$ 199.41 |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 203,881 | 286,914 | 16.1% | 98.5% | \$ 20.62 | \$ 0.72 | \$ 1.29 | \$ 67.35 | \$ 99.15 | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Imports | | 4,456 | | 1.5% | | | | | \$ 99.15 | |
| Total | | 291,370 | | 54 | | | | | \$ 99.15 | |
| | | | | | Total Expenditure (\$B) | | | | | Total Cost (\$/MWh) |
| | | | | | \$28.9 | | | | | \$ 99.15 |

| | % Total Load | % of Grid Renewables |
|-------------------------|--------------|----------------------|
| Unmet Load | 0 | 0.0% |
| Renewable Curtailments | 68,309 | 23.4% |
| New Nuclear Curtailment | 0 | 0.0% |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 149 |
| Days Batteries Discharged | 252 |
| Days Batteries Not Fully Charged | 111 |

** Firm sources = gas, coal, oil, flex nuclear

EP CET Policy Scenario (Figure 3.2)

| EP CET Policy Scenario Year: 2050 | | | | | Current Costs | | | | | |
|---|----------------|---------------------|---------------------|--------------|-------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Generation Summary | | | | | | | | | | |
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | 27,538 | 22,505 | 9.3% | 11.5% | \$ 1,500 | \$ 26.92 | \$ - | \$ - | \$ 128.48 | \$ 155.40 |
| Land-based Wind | 7,500 | 15,952 | 24.3% | 8.2% | \$ 1,650 | \$ 15.05 | \$ - | \$ - | \$ 54.30 | \$ 69.35 |
| Offshore Wind | 34,406 | 86,479 | 28.7% | 44.3% | \$ 6,500 | \$ 35.81 | \$ - | \$ - | \$ 181.02 | \$ 216.83 |
| SubTotal | 87,258 | 180,276 | 23.6% | 92.3% | \$ 25.59 | \$ 0.42 | \$ 0.60 | \$ 119.96 | \$ 146.57 | |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 27,500 | 9,524 | 4.0% | 4.9% | \$ 2,080 | \$ 138.59 | \$ - | \$ - | \$ 420.40 | \$ 558.99 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 25,000 | 11,352 | 5.2% | 5.8% | \$ 1,500 | \$ 74.88 | \$ 2.00 | \$ 17.00 | \$ 231.24 | \$ 325.12 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 52,500 | 11,352 | 2.5% | 5.8% | \$ 103.95 | \$ 1.09 | \$ 9.24 | \$ 317.54 | \$ 431.81 | |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 139,758 | 191,628 | 15.7% | 98.1% | \$ 30.23 | \$ 0.46 | \$ 1.11 | \$ 131.66 | \$ 184.93 | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Imports | | 3,723 | | 1.9% | | | | | \$ 184.93 | |
| Total | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Total Expenditure (\$B) | | | | Total Cost (\$/MWh) | |
| Total | | 195,352 | | | \$36.1 | | | | \$ 184.93 | |

| Generation Summary | | | | | Projected Costs | | | | | |
|---|----------------|---------------------|---------------------|--------------|-------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | 27,538 | 22,505 | 9.3% | 11.5% | \$ 700 | \$ 17.13 | \$ - | \$ - | \$ 59.96 | \$ 77.09 |
| Land-based Wind | 7,500 | 15,952 | 24.3% | 8.2% | \$ 1,100 | \$ 12.22 | \$ - | \$ - | \$ 36.20 | \$ 48.43 |
| Offshore Wind | 34,406 | 86,479 | 28.7% | 44.3% | \$ 3,500 | \$ 27.85 | \$ - | \$ - | \$ 97.47 | \$ 125.32 |
| SubTotal | 87,258 | 180,276 | 23.6% | 92.3% | \$ 19.60 | \$ 0.42 | \$ 0.60 | \$ 62.16 | \$ 82.78 | |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 27,500 | 9,524 | 4.0% | 4.9% | \$ 1,140 | \$ 72.18 | \$ - | \$ - | \$ 230.41 | \$ 302.59 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 25,000 | 11,352 | 5.2% | 5.8% | \$ 1,200 | \$ 44.05 | \$ 2.00 | \$ 17.00 | \$ 184.99 | \$ 248.04 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 52,500 | 11,352 | 2.5% | 5.8% | \$ 56.88 | \$ 1.09 | \$ 9.24 | \$ 205.71 | \$ 272.93 | |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 139,758 | 191,628 | 15.7% | 98.1% | \$ 21.81 | \$ 0.46 | \$ 1.11 | \$ 70.66 | \$ 107.61 | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Imports | | 3,723 | | 1.9% | | | | | \$ 107.61 | |
| Total | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Total Expenditure (\$B) | | | | Total Cost (\$/MWh) | |
| Total | | 195,352 | | | \$21.0 | | | | \$ 107.61 | |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 125 |
| Days Batteries Discharged | 235 |
| Days Batteries Not Fully Charged | 116 |

** Firm sources = gas, coal, oil, flex nuclear

| | GWh/yr | % Total Load | % of Grid Renewables |
|-------------------------|--------|--------------|----------------------|
| Unmet Load | 12 | 0.0% | |
| Renewable Curtailments | 53,884 | 27.6% | 24.6% |
| New Nuclear Curtailment | 0 | 0.0% | |

EPCET Policy Scenario w/0% Renewable Energy & Baseload Nuclear (Figure 4.1)

| EPCET Policy Scenario w/0% RE & Baseload Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|--------------|--------------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Generation Summary | | | | | Current Costs | | | | | |
| | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Non-dispatchable* | | | | | | | | | | |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 |
| New Nuclear | 18,000 | 131,341 | 83.3% | 67.9% | \$ 7,600 | \$ 23.98 | \$ 0.97 | \$ 3.40 | \$ 72.91 | \$ 101.26 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | - | - | 0.0% | 0.0% | \$ 1,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Land-based Wind | - | - | 0.0% | 0.0% | \$ 1,650 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Offshore Wind | - | - | 0.0% | 0.0% | \$ 6,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| SubTotal | 30,080 | 179,695 | 68.2% | 92.8% | | \$ 20.31 | \$ 1.13 | \$ 3.09 | \$ 58.46 | \$ 82.98 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | | | | | | | | | | |
| Battery Discharge | 0 | 0 | 0.0% | 0.0% | \$ 2,080 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 25,000 | 10,738 | 4.9% | 5.5% | \$ 1,500 | \$ 79.16 | \$ 2.00 | \$ 17.00 | \$ 244.45 | \$ 342.61 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 25,000 | 10,738 | 4.9% | 5.5% | | \$ 79.16 | \$ 2.00 | \$ 17.00 | \$ 244.45 | \$ 342.61 |
| Total In-Region Generation | | | | | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | | | | | \$ 23.62 | \$ 1.18 | \$ 3.87 | \$ 68.94 | \$ 97.62 | |
| Regional Purchases | | | | | | | | | | Import Purchase Cost (\$/MWh) |
| Imports | | | | | | | | | | \$ 97.62 |
| Total | | | | | Total Expenditure (\$B) | | | | | Total Cost (\$/MWh) |
| Total | | | | | \$18.9 | | | | | \$ 97.62 |

| EPCET Policy Scenario w/0% RE & Baseload Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|--------------|--------------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Generation Summary | | | | | Projected Costs | | | | | |
| | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Non-dispatchable* | | | | | | | | | | |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| New Nuclear | 18,000 | 131,341 | 83.3% | 67.9% | \$ 5,000 | \$ 23.98 | \$ 0.97 | \$ 3.40 | \$ 47.97 | \$ 76.32 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | - | - | 0.0% | 0.0% | \$ 700 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Land-based Wind | - | - | 0.0% | 0.0% | \$ 1,100 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Offshore Wind | - | - | 0.0% | 0.0% | \$ 3,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| SubTotal | 30,080 | 179,695 | 68.2% | 92.8% | | \$ 20.02 | \$ 1.13 | \$ 3.09 | \$ 37.11 | \$ 61.34 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | | | | | | | | | | |
| Battery Discharge | 0 | 0 | 0.0% | 0.0% | \$ 1,140 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 25,000 | 10,738 | 4.9% | 5.5% | \$ 1,200 | \$ 46.56 | \$ 2.00 | \$ 17.00 | \$ 195.56 | \$ 261.13 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 25,000 | 10,738 | 4.9% | 5.5% | | \$ 46.56 | \$ 2.00 | \$ 17.00 | \$ 195.56 | \$ 261.13 |
| Total In-Region Generation | | | | | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | | | | | \$ 21.51 | \$ 1.18 | \$ 3.87 | \$ 46.04 | \$ 72.61 | |
| Regional Purchases | | | | | | | | | | Import Cost (\$/MWh) |
| Imports | | | | | | | | | | \$ 72.61 |
| Total | | | | | Total Expenditure (\$B) | | | | | Total Cost (\$/MWh) |
| Total | | | | | \$14.1 | | | | | \$ 72.61 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 201 |
| Days Batteries Discharged | 0 |
| Days Batteries Not Fully Charged | 0 |

** Firm sources = gas, coal, oil, flex nuclear

| | | | |
|-------------------------|--------|------|------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 0 | 0.0% | 0.0% |
| New Nuclear Curtailment | 14,077 | 7.3% | |

EPCET Policy Scenario w/20% Renewable Energy & Baseload Nuclear (Figure 4.2)

| EPCET Policy Scenario w/20% RE & Baseload Nuclear | | | | | | Year: 2050 | | | | | |
|---|---------------|---------------------|---------------------|-------------------------------|----------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|--|
| Generation Summary | | | | | Current Costs | | | | | | |
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 | |
| New Nuclear | 14,000 | 111,430 | 90.9% | 57.5% | \$ 7,600 | \$ 21.99 | \$ 0.97 | \$ 3.40 | \$ 66.84 | \$ 93.20 | |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 | |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 | |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 | |
| Utility Solar | 5,500 | 3,290 | 6.8% | 1.7% | \$ 1,500 | \$ 36.78 | \$ - | \$ - | \$ 175.54 | \$ 212.32 | |
| Land-based Wind | 1,500 | 2,867 | 21.8% | 1.5% | \$ 1,650 | \$ 16.74 | \$ - | \$ - | \$ 60.44 | \$ 77.18 | |
| Offshore Wind | 6,880 | 14,748 | 24.5% | 7.6% | \$ 6,500 | \$ 41.99 | \$ - | \$ - | \$ 212.26 | \$ 254.25 | |
| SubTotal | 39,960 | 180,688 | 51.6% | 93.2% | \$ - | \$ 20.68 | \$ 1.02 | \$ 2.70 | \$ 67.84 | \$ 92.24 | |
| * Battery charging included in solar and wind generation. | | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Battery Discharge | 5,500 | 1,293 | 2.7% | 0.7% | \$ 2,080 | \$ 204.12 | \$ - | \$ - | \$ 619.15 | \$ 823.27 | |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - | |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | |
| Gas | 25,000 | 9,572 | 4.4% | 4.9% | \$ 1,500 | \$ 88.80 | \$ 2.00 | \$ 17.00 | \$ 274.23 | \$ 382.03 | |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | |
| SubTotal | 30,500 | 9,572 | 3.6% | 4.9% | \$ - | \$ 102.53 | \$ 1.76 | \$ 14.98 | \$ 315.29 | \$ 434.56 | |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | | |
| Total | 70,460 | 190,260 | 30.8% | 98.2% | \$ 24.80 | \$ 1.06 | \$ 3.31 | \$ 80.29 | \$ 112.41 | | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | % Total Load | Import Purchase Cost (\$/MWh) | | | | | | | |
| Imports | | 3,540 | 1.8% | \$ 112.41 | | | | | | | |
| Total | Capacity (MW) | Generation (GWh/yr) | Peak Load (GW) | Total Expenditure (\$B) | Total Cost (\$/MWh) | | | | | | |
| Total | 70,460 | 193,801 | 36 | \$21.8 | \$ 112.41 | | | | | | |

| Generation Summary | | | | | Projected Costs | | | | | |
|---|---------------|---------------------|---------------------|-------------------------|----------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| New Nuclear | 14,000 | 111,430 | 90.9% | 57.5% | \$ 5,000 | \$ 21.99 | \$ 0.97 | \$ 3.40 | \$ 43.97 | \$ 70.33 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | 5,500 | 3,290 | 6.8% | 1.7% | \$ 700 | \$ 23.41 | \$ - | \$ - | \$ 81.92 | \$ 105.33 |
| Land-based Wind | 1,500 | 2,867 | 21.8% | 1.5% | \$ 1,100 | \$ 13.60 | \$ - | \$ - | \$ 40.29 | \$ 53.89 |
| Offshore Wind | 6,880 | 14,748 | 24.5% | 7.6% | \$ 3,500 | \$ 32.66 | \$ - | \$ - | \$ 114.29 | \$ 146.95 |
| SubTotal | 39,960 | 180,688 | 51.6% | 93.2% | \$ - | \$ 19.34 | \$ 1.02 | \$ 2.70 | \$ 40.62 | \$ 63.67 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 5,500 | 1,293 | 2.7% | 0.7% | \$ 1,140 | \$ 106.31 | \$ - | \$ - | \$ 339.34 | \$ 445.65 |
| Flex Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 25,000 | 9,572 | 4.4% | 4.9% | \$ 1,200 | \$ 52.24 | \$ 2.00 | \$ 17.00 | \$ 219.39 | \$ 290.62 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 30,500 | 9,572 | 3.6% | 4.9% | \$ - | \$ 58.67 | \$ 1.76 | \$ 14.98 | \$ 233.67 | \$ 309.08 |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 70,460 | 190,260 | 30.8% | 98.2% | \$ 21.32 | \$ 1.06 | \$ 3.31 | \$ 50.33 | \$ 78.12 | |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | % Total Load | Import Cost (\$/MWh) | | | | | | |
| Imports | | 3,540 | 1.8% | \$ 78.12 | | | | | | |
| Total | Capacity (MW) | Generation (GWh/yr) | Peak Load (GW) | Total Expenditure (\$B) | Total Cost (\$/MWh) | | | | | |
| Total | 70,460 | 193,801 | 36 | \$15.1 | \$ 78.12 | | | | | |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 136 |
| Days Batteries Discharged | 163 |
| Days Batteries Not Fully Charged | 134 |

** Firm sources = gas, coal, oil, flex nuclear

| | | | |
|-------------------------|--------|--------------|----------------------|
| | GWh/yr | % Total Load | % of Grid Renewables |
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 14,846 | 7.7% | 22.1% |
| New Nuclear Curtailment | 1,672 | 0.9% | |

EPCET Policy Scenario w/Flex Nuclear (Figure 5.1)

| EPCET Policy Scenario w/Flex Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|---------------------|-------------------------|--------------------|--------------------|---------------------------|------------------------------------|------------------------------------|
| Generation Summary | | | | | Current Costs | | | | | |
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 |
| New Nuclear | 0 | 0 | 0.0% | 0.0% | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% | \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | 27,538 | 22,431 | 9.3% | 11.5% | \$ 1,500 | \$ 27.01 | \$ - | \$ - | \$ 128.90 | \$ 155.91 |
| Land-based Wind | 7,500 | 15,936 | 24.3% | 8.2% | \$ 1,650 | \$ 15.06 | \$ - | \$ - | \$ 54.36 | \$ 69.42 |
| Offshore Wind | 34,406 | 86,422 | 28.7% | 44.3% | \$ 6,500 | \$ 35.83 | \$ - | \$ - | \$ 181.14 | \$ 216.97 |
| SubTotal | 87,258 | 180,130 | 23.6% | 92.2% | \$ - | \$ 25.61 | \$ 0.42 | \$ 0.60 | \$ 120.05 | \$ 146.69 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 27,500 | 9,399 | 3.9% | 4.8% | \$ 2,080 | \$ 140.44 | \$ - | \$ - | \$ 426.01 | \$ 566.45 |
| Flex Nuclear | 28,000 | 10,958 | 4.5% | 5.6% | \$ 9,600 | \$ 347.52 | \$ 1.20 | \$ 2.60 | \$ 1,717.15 | \$ 2,068.47 |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 55,500 | 10,958 | 2.3% | 5.6% | \$ - | \$ 251.91 | \$ 0.65 | \$ 1.40 | \$ 1,121.02 | \$ 1,374.97 |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) | |
| Total | 142,758 | 191,087 | 15.3% | 97.8% | \$ - | \$ 38.59 | \$ 0.44 | \$ 0.65 | \$ 177.45 | \$ 284.75 |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | | | | | | |
| Imports | | 4,212 | | 2.2% | | | | | | |
| | | | | Total Load (GWh/yr) | Peak Load (GW) | | | | | |
| Total | | 195,300 | | 36 | | | | | | |
| | | | | | Total Expenditure (\$B) | | | | | |
| | | | | | \$55.6 | | | | | |
| | | | | | Total Cost (\$/MWh) | | | | | |
| | | | | | \$ 284.75 | | | | | |

| Generation Summary | | | | |
|---|---------------|---------------------|---------------------|--------------|
| Non-dispatchable* | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.6% |
| New Nuclear | 0 | 0 | 0.0% | 0.0% |
| Hydro | 3,991 | 11,792 | 33.7% | 6.0% |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% |
| Rooftop Solar | 9,734 | 11,860 | 13.9% | 6.1% |
| Utility Solar | 27,538 | 22,431 | 9.3% | 11.5% |
| Land-based Wind | 7,500 | 15,936 | 24.3% | 8.2% |
| Offshore Wind | 34,406 | 86,422 | 28.7% | 44.3% |
| SubTotal | 87,258 | 180,130 | 23.6% | 92.2% |
| * Battery charging included in solar and wind generation. | | | | |
| Dispatchable | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load |
| Battery Discharge | 27,500 | 9,399 | 3.9% | 4.8% |
| Flex Nuclear | 28,000 | 10,958 | 4.5% | 5.6% |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% |
| Gas | 0 | 0 | 0.0% | 0.0% |
| Oil | 0 | 0 | 0.0% | 0.0% |
| Coal | 0 | 0 | 0.0% | 0.0% |
| SubTotal | 55,500 | 10,958 | 2.3% | 5.6% |
| Total In-Region Generation | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load |
| Total | 142,758 | 191,087 | 15.3% | 97.8% |
| Regional Purchases | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load |
| Imports | | 4,212 | | 2.2% |
| | | Total Load (GWh/yr) | Peak Load (GW) | |
| Total | | 195,300 | 36 | |

| Projected Costs | | | | | |
|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| \$ - | \$ 14.82 | \$ 1.48 | \$ - | \$ - | \$ 16.30 |
| \$ - | \$ 19.27 | \$ 5.06 | \$ - | \$ - | \$ 24.33 |
| \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| \$ 700 | \$ 17.19 | \$ - | \$ - | \$ 60.16 | \$ 77.34 |
| \$ 1,100 | \$ 12.24 | \$ - | \$ - | \$ 36.24 | \$ 48.48 |
| \$ 3,500 | \$ 27.87 | \$ - | \$ - | \$ 97.54 | \$ 125.41 |
| \$ | \$ 19.61 | \$ 0.42 | \$ 0.60 | \$ 62.21 | \$ 82.85 |
| Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| \$ 1,140 | \$ 73.15 | \$ - | \$ - | \$ 233.49 | \$ 306.63 |
| \$ 4,900 | \$ 347.52 | \$ 1.20 | \$ 2.60 | \$ 876.46 | \$ 1,227.78 |
| \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| \$ | \$ 220.84 | \$ 0.65 | \$ 1.40 | \$ 579.59 | \$ 802.48 |
| | | | | | In-Region Generation Cost (\$/MWh) |
| | | | | | \$ 163.59 |
| | | | | | Import Cost (\$/MWh) |
| | | | | | \$ 163.59 |
| | | | | | Total Cost (\$/MWh) |
| | | | | | \$ 163.59 |
| | | | | | Total Expenditure (\$B) |
| | | | | | \$31.9 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 120 |
| Days Batteries Discharged | 234 |
| Days Batteries Not Fully Charged | 115 |

** Firm sources = gas, coal, oil, flex nuclear

| | GWh/yr | % Total Load | % of Grid Renewables |
|-------------------------|--------|--------------|----------------------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 54,031 | 27.7% | 26.0% |
| New Nuclear Curtailment | 0 | 0.0% | |

EPCET Policy Scenario w/0% Renewable Energy & Baseload & Flex Nuclear (Figure 5.2)

| EPCET w/0% RE & Baseload & Flex Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Generation Summary | | | | | Current Costs | | | | | |
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.24 | \$ 10.46 |
| New Nuclear | 14,000 | 111,386 | 90.8% | 57.6% | \$ 7,600 | \$ 22.00 | \$ 0.97 | \$ 3.40 | \$ 66.87 | \$ 93.23 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | | \$ 14.82 | \$ 1.48 | | | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | | \$ 19.27 | \$ 5.06 | | | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | - | - | 0.0% | 0.0% | \$ 1,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Land-based Wind | - | - | 0.0% | 0.0% | \$ 1,650 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Offshore Wind | - | - | 0.0% | 0.0% | \$ 6,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| SubTotal | 26,080 | 159,740 | 69.9% | 82.6% | | \$ 18.46 | \$ 1.15 | \$ 3.05 | \$ 52.44 | \$ 75.10 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 0 | 0 | 0.0% | 0.0% | \$ 2,080 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Flex Nuclear | 20,000 | 27,410 | 15.6% | 14.2% | \$ 9,600 | \$ 99.23 | \$ 1.20 | \$ 2.60 | \$ 490.32 | \$ 593.36 |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 20,000 | 27,410 | 15.6% | 14.2% | | \$ 99.23 | \$ 1.20 | \$ 2.60 | \$ 490.32 | \$ 593.36 |
| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Total | 46,080 | 187,150 | 46.4% | 96.7% | | \$ 30.29 | \$ 1.16 | \$ 2.98 | \$ 116.57 | \$ 151.01 |
| <i>Regional Purchases</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Imports | | 6,352 | | 3.3% | | | | | | \$ 151.01 |
| Total | | 193,502 | | 36 | | | | \$29.2 | | \$ 151.01 |

| EPCET w/0% RE & Baseload & Flex Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Generation Summary | | | | | Projected Costs | | | | | |
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.23 | \$ 10.45 |
| New Nuclear | 12,000 | 96,812 | 92.1% | 50.0% | \$ 5,000 | \$ 21.69 | \$ 0.97 | \$ 3.40 | \$ 43.38 | \$ 69.44 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | | \$ 14.82 | \$ 1.48 | | | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | | \$ 19.27 | \$ 5.06 | | | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | - | - | 0.0% | 0.0% | \$ 700 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Land-based Wind | - | - | 0.0% | 0.0% | \$ 1,100 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Offshore Wind | - | - | 0.0% | 0.0% | \$ 3,500 | \$ - | \$ - | \$ - | \$ - | \$ - |
| SubTotal | 24,080 | 145,166 | 68.8% | 75.0% | | \$ 17.54 | \$ 1.17 | \$ 3.01 | \$ 31.47 | \$ 53.20 |
| * Battery charging included in solar and wind generation. | | | | | | | | | | |
| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Battery Discharge | 0 | 0 | 0.0% | 0.0% | \$ 1,140 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Flex Nuclear | 23,000 | 40,715 | 20.2% | 21.0% | \$ 4,900 | \$ 76.83 | \$ 1.20 | \$ 2.60 | \$ 193.76 | \$ 274.39 |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 34.00 | \$ 0.00 | \$ 34.00 |
| Gas | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 23,000 | 40,715 | 20.2% | 21.0% | | \$ 76.83 | \$ 1.20 | \$ 2.60 | \$ 193.76 | \$ 274.39 |
| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Total | 47,080 | 185,881 | 45.1% | 96.1% | | \$ 30.53 | \$ 1.18 | \$ 2.92 | \$ 67.02 | \$ 101.65 |
| <i>Regional Purchases</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Imports | | 7,643 | | 3.9% | | | | | | \$ 101.65 |
| Total | | 193,523 | | 36 | | | | \$19.7 | | \$ 101.65 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 366 |
| Days Batteries Discharged | 0 |
| Days Batteries Not Fully Charged | 0 |

** Firm sources = gas, coal, oil, flex nuclear

| | GWh/yr | % Total Load | % of Grid Renewables |
|-------------------------|--------|--------------|----------------------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 0 | 0.0% | 0.0% |
| New Nuclear Curtailment | 133 | 0.1% | |

EPCET Policy Scenario w/20% Renewable Energy & Baseload & Flex Nuclear (Figure 5.3)

| EPCET Policy Scenario w/20% RE & Baseload & Flex Nuclear Year: 2050 | | | | | | | | | | |
|---|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Generation Summary | | | | | Current Costs | | | | | |
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 141 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.22 | \$ 10.44 |
| New Nuclear | 10,000 | 80,782 | 92.2% | 41.7% | \$ 7,600 | \$ 21.66 | \$ 0.97 | \$ 3.40 | \$ 65.86 | \$ 91.89 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ | \$ 14.82 | \$ 1.48 | \$ | \$ | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ | \$ | \$ 19.27 | \$ 5.06 | \$ - | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 3,200 | \$ 24.62 | \$ - | \$ - | \$ 183.85 | \$ 208.47 |
| Utility Solar | 5,500 | 5,927 | 12.3% | 3.1% | \$ 1,500 | \$ 20.42 | \$ - | \$ - | \$ 97.44 | \$ 117.86 |
| Land-based Wind | 1,500 | 3,904 | 29.7% | 2.0% | \$ 1,650 | \$ 12.30 | \$ - | \$ - | \$ 44.38 | \$ 56.67 |
| Offshore Wind | 6,880 | 22,562 | 37.4% | 11.6% | \$ 6,500 | \$ 27.44 | \$ - | \$ - | \$ 138.75 | \$ 166.19 |
| SubTotal | 35,960 | 161,529 | 51.3% | 83.3% | \$ | \$ 18.80 | \$ 0.96 | \$ 2.37 | \$ 62.71 | \$ 84.84 |

* Battery charging included in solar and wind generation.

| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|---------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Battery Discharge | 5,500 | 1,275 | 2.6% | 0.7% | \$ 2,080 | \$ 207.02 | \$ - | \$ - | \$ 627.96 | \$ 834.98 |
| Flex Nuclear | 25,000 | 25,954 | 11.9% | 13.4% | \$ 9,600 | \$ 131.00 | \$ 1.20 | \$ 2.60 | \$ 647.29 | \$ 782.09 |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Gas | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 30,500 | 25,954 | 9.7% | 13.4% | \$ | \$ 134.56 | \$ 1.14 | \$ 2.48 | \$ 646.39 | \$ 784.57 |

| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|-----------------------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Total | 66,460 | 187,483 | 32.2% | 96.7% | \$ | \$ 34.83 | \$ 0.98 | \$ 2.39 | \$ 143.51 | \$ 187.04 |

| <i>Regional Purchases</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|---------------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Imports | | 6,313 | | 3.3% | | | | | | \$ 187.04 |

| <i>Total</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|--------------|----------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Total | 193,797 | 193,797 | 36 | 36 | \$ 36.2 | \$ | \$ | \$ | \$ | \$ 187.04 |

| Generation Summary | | | | | | | | | | |
|--------------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| <i>Non-dispatchable*</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
| Existing Nuclear | 3,326 | 26,478 | 90.9% | 13.7% | \$ 140 | \$ 3.91 | \$ 1.22 | \$ 4.09 | \$ 1.21 | \$ 10.44 |
| New Nuclear | 10,000 | 80,782 | 92.2% | 41.7% | \$ 5,000 | \$ 21.66 | \$ 0.97 | \$ 3.40 | \$ 43.33 | \$ 69.36 |
| Hydro | 3,991 | 11,792 | 33.7% | 6.1% | \$ | \$ 14.82 | \$ 1.48 | \$ | \$ | \$ 16.30 |
| Other Renewables | 763 | 5,210 | 78.0% | 2.7% | \$ | \$ | \$ 19.27 | \$ 5.06 | \$ - | \$ 24.33 |
| Rooftop Solar | 4,000 | 4,874 | 13.9% | 2.5% | \$ 1,200 | \$ 13.95 | \$ - | \$ - | \$ 68.94 | \$ 82.90 |
| Utility Solar | 5,500 | 5,927 | 12.3% | 3.1% | \$ 700 | \$ 12.99 | \$ - | \$ - | \$ 45.47 | \$ 58.46 |
| Land-based Wind | 1,500 | 3,904 | 29.7% | 2.0% | \$ 1,100 | \$ 9.99 | \$ - | \$ - | \$ 29.59 | \$ 39.58 |
| Offshore Wind | 6,880 | 22,562 | 37.4% | 11.6% | \$ 3,500 | \$ 21.35 | \$ - | \$ - | \$ 74.71 | \$ 96.06 |
| SubTotal | 35,960 | 161,529 | 51.3% | 83.3% | \$ | \$ 17.30 | \$ 0.96 | \$ 2.37 | \$ 36.77 | \$ 57.39 |

* Battery charging included in solar and wind generation.

| <i>Dispatchable</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|---------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Battery Discharge | 5,500 | 1,275 | 2.6% | 0.7% | \$ 1,140 | \$ 107.82 | \$ - | \$ - | \$ 344.17 | \$ 451.99 |
| Flex Nuclear | 25,000 | 25,954 | 11.9% | 13.4% | \$ 4,900 | \$ 131.00 | \$ 1.20 | \$ 2.60 | \$ 330.39 | \$ 465.19 |
| Synfuel Turbine | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 55.00 | \$ 0.00 | \$ 55.00 |
| Gas | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Oil | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| Coal | 0 | 0 | 0.0% | 0.0% | \$ - | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 | \$ 0.00 |
| SubTotal | 30,500 | 25,954 | 9.7% | 13.4% | \$ | \$ 129.91 | \$ 1.14 | \$ 2.48 | \$ 331.03 | \$ 464.57 |

| <i>Total In-Region Generation</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|-----------------------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Total | 66,460 | 187,483 | 32.2% | 96.7% | \$ | \$ 32.89 | \$ 0.98 | \$ 2.39 | \$ 77.50 | \$ 116.92 |

| <i>Regional Purchases</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|---------------------------|---------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Imports | | 6,313 | | 3.3% | | | | | | \$ 116.92 |

| <i>Total</i> | Capacity (MW) | Generation (GWh/yr) | Capacity Factor (%) | % Total Load | Capital Cost (\$/kw) | Fixed O&M (\$/MWh) | Var O&M (\$/MWh) | Fuel Cost (\$/MWh) | Capital Recovery (\$/MWh) | In-Region Generation Cost (\$/MWh) |
|--------------|----------------|---------------------|---------------------|--------------|----------------------|--------------------|------------------|--------------------|---------------------------|------------------------------------|
| Total | 193,797 | 193,797 | 36 | 36 | \$ 22.7 | \$ | \$ | \$ | \$ | \$ 116.92 |

| | |
|----------------------------------|-----|
| Days Firm Sources Needed** | 276 |
| Days Batteries Discharged | 147 |
| Days Batteries Not Fully Charged | 271 |

** Firm sources = gas, coal, oil, flex nuclear

| | GWh/yr | % Total Load | % of Grid Renewables |
|-------------------------|--------|--------------|----------------------|
| Unmet Load | 0 | 0.0% | |
| Renewable Curtailments | 3,358 | 1.7% | 5.8% |
| New Nuclear Curtailment | 5 | 0.0% | |